Inventory of Cogeneration Potential in Minnesota

Minnesota Planning
Minnesota Environmental Quality Board

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Executive Summary

Background

In June 1999 the Legislative Commission on Minnesota Resources (LCMR) directed the Minnesota Environmental Quality Board and Minnesota Planning to prepare a report on the potential for cogeneration in Minnesota. Cogeneration, or Combined Heat and Power, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A cogeneration system most commonly utilizes a fuel source to produce steam that can be used to generate electricity and thermal energy that can be used in industrial processes. Interest in cogeneration has grown significantly in recent years due to its energy efficiency benefits and associated reductions in air pollution and greenhouse gas emissions.

The overall goal of this project was to develop a statewide inventory and description of promising cogeneration sites in Minnesota in order to encourage the implementation of cogeneration. The specific objectives of the project were to

1. develop measurable criteria for evaluation of cogeneration viability and an approach for applying these criteria to evaluate the site-specific feasibility of cogeneration for industrial and district energy systems;

2. identify potential cogeneration sites in Minnesota and provide enough information about these sites to allow cogeneration developers to make a preliminary assessment of cogeneration viability;

3. prioritize the potential sites, based on the data gathered, in order to focus development efforts on the opportunities with the best potential;

4. provide a general evaluation of the potential for increased cogeneration in Minnesota and the associated energy efficiency benefits; and

5. provide an overview of various cogeneration technologies.

The Minnesota Environmental Quality Board hired the consulting firm Kattner, FVB, Inc. to identify factors that affect the potential for cogeneration and to conduct a survey of industrial sources in Minnesota regarding the potential for implementation of a cogeneration facility. In May, 2001 Kattner submitted its report to the EQB.

Criteria for Evaluation of Cogeneration Viability

The most important parameters for screening and prioritizing cogeneration opportunities are:

- Size of thermal and power loads, and the relationship between the two;
- Thermal and electric load factors;

- Age of existing thermal facilities and plans for replacement or additional capacity;
- Avoided costs and/or potential revenue for generated power; and
- Fuel supply availability and costs.

Conduct of Study

Kattner's first task was to identify the sources in Minnesota that have facilities burning fuels for thermal energy. For this task, Kattner reviewed the database maintained by the Minnesota Pollution Control Agency on all boilers operated in the State. The MPCA has information on boilers at 552 facilities in the State. Of these facilities, 164 burn more than 100,000 million BTUs (mmBTU) per year and account for over 80% of the fuel burned at such facilities. For purposes of this survey, the smaller facilities burning less than 100,000 mmBTU/year were excluded from the survey, as were the 17 power plants in the State. Although power plants burn 77% of the total fuel consumed in Minnesota, they are designed to achieve maximum electric energy production, not a combination of electric and thermal energy.

Kattner then prepared a survey form containing questions asking for the pertinent information. Kattner selected 142 of the larger sites to include in the survey. Each of these operators was mailed a copy of the survey form with a cover letter explaining the purpose of the survey. Thirty-two of the recipients responded to the survey, and these responses are the basis for the conclusions in this report.

Sites with High Potential for Cogeneration

The study identified four high potential cogeneration sites among survey respondents. An initial site evaluation was performed on three of the sites. These sites are:

- Rahr Malting (Shakopee) – Two options were examined: a 9.3 MW steam turbine cogeneration fueled with biomass; and a 10.4 MW combustion turbine fueled with natural gas.

- Chippewa Valley Ethanol (Benson) – Two options were examined: 3.4 MW and 7.4 MW combustion turbines fueled with natural gas.

- Duluth Steam Cooperative (Duluth) – Two small backpressure steam turbines, totaling 0.9 MW, added to an existing coal-fired boiler facility.

- St. Mary's Duluth Clinic Health Systems (Duluth) – This facility was not evaluated.

Key tasks in each analysis included:

- Analysis of the existing systems for production or purchase of electric and thermal energy and a review of the pertinent costs.
- Identification of potentially feasible cogeneration technologies and fuels, and outline a proposed method of operation for the cogeneration system.

- Analysis of the operating costs of appropriately sized cogeneration systems, and the resulting net operating cost savings.
- Estimation of the capital costs for the cogeneration system.
- Comparison of the capital costs to the net cost savings to estimate a simple payback.

Based on survey responses, ten other sites showed some potential for cogeneration but the data are incomplete to adequately review these sites.

Cogeneration Potential in Minnesota

Based on the results of the survey, there is a technical potential of 1600 to 2100 megawatts (MW) of cogeneration at existing sites in Minnesota. This estimate takes into account the power and thermal demand characteristics of the survey respondents and the relationship of these demands to fuel use, and applies these characteristics to the total fuel use by facilities reporting over 100,000 MMBtu per year fuel consumption to the MPCA. Generally cogeneration facilities at these facilities would have power generation exceeding 1 megawatt. Another study, performed by Kattner/FVB District Energy, Inc. in 1999, focused on small energy users and estimated the technical potential for small cogeneration (under 1 MW) to be 842 MW.

However, economic conditions – specifically the relatively low cost of purchased power, the low utility buy-back rates under the Public Utilities Regulatory Policies Act of 1978 (PURPA), P.L. 95-617., and the volatility of natural gas prices – provide significant economic constraints to cogeneration opportunities that are technically feasible. The 1992 Energy Policy Act, P.L. 102-486, introduced the option for small producers to sell power at wholesale rates. Though lower than retail rates, wholesale rates are still higher than the avoided cost limitations that have been available to small power producers for over 20 years through PURPA. As the market for small power sales continues to develop, the economics for cogeneration will improve.

The economics of cogeneration based on current prices of power (1.0 to 6.5 cents/kilowatt hour) and natural gas ($3 to $6 per thousand cubic feet) are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no reason to design the facility to generate more power than needed on site if the excess power can't be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become attractive. It remains to be seen how federal policy will impact the economics of cogeneration.

Cogeneration Technologies

The relative economic and performance attributes of gas turbines, reciprocating engines, steam turbines, combined-cycles and fuel cells are described in an appendix to the report.

1. Introduction

1.1 Background

In June 1999 the Legislative Commission on Minnesota Resources (LCMR) directed the Minnesota Environmental Quality Board to prepare a report on the potential for cogeneration in Minnesota. Cogeneration, or Combined Heat and Power, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A cogeneration system most commonly utilizes a fuel source to produce steam that can be used to generate electricity and thermal energy that can be used in industrial processes. Interest in cogeneration has grown significantly in recent years due to its energy efficiency benefits and associated reductions in air pollution and greenhouse gas emissions. Evidence of this interest includes:

- The U.S. Department of Energy (DOE) announced in December 1998 a goal to double the use of cogeneration by 2010.

- The U.S. Combined Heat and Power Association was formed during 1999.

- DOE has funded a variety of projects relating to CHP, including development of a guidebook for CHP developers and research on combined heating, cooling and power generation in building-scale systems.

- The International Energy Agency (IEA) has sponsored research on a variety of CHP topics, integrating CHP with district cooling.

- The International Energy Agency is sponsoring research on CHP and district energy as a climate change strategy and use of carbon emissions trading as a key implementation mechanism.

1.2 Purpose of Report

The overall goal of this project was to develop a statewide inventory and description of promising cogeneration sites in Minnesota in order to encourage the implementation of cogeneration.

The specific objectives of the project were to:

1. develop measurable criteria for evaluation of cogeneration viability and an approach for applying these criteria to evaluate the site-specific feasibility of cogeneration for industrial and district energy systems;

2. identify potential cogeneration sites in Minnesota and provide enough information about these sites to allow cogeneration developers to make a preliminary assessment of cogeneration viability;

3. prioritize the potential sites, based on the data gathered, in order to focus development efforts on the opportunities with the best potential;

4. provide a general evaluation of the potential for increased cogeneration in Minnesota and the associated energy efficiency benefits; and

5. provide an overview of various cogeneration technologies.

1.3 Organization of Report

Chapter 1 is an Introduction. Chapter 2 describes the factors affecting the feasibility of cogeneration. Chapter 3 discusses the survey conducted of 142 different industries with more detailed information presented in appendices. Chapter 4 presents the results of the survey. Chapter 5 identifies the facilities in Minnesota that have the greatest potential for cogeneration. Chapter 6 provides an assessment of the cogeneration potential in Minnesota. Appendices present cogeneration terminologies and technologies as well as more detailed information on survey results and analysis.

2. Factors Affecting Cogeneration

2.1 Overview

The most important parameters for screening and prioritizing cogeneration opportunities are:

- Size of thermal and power loads, and the relationship between the two;
- Thermal and electric load factors;
- Age of existing thermal facilities and plans for replacement or additional capacity;
- Avoided costs and/or potential revenue for generated power; and
- Fuel supply availability and costs.

2.2 Size of thermal and power loads

The size of the thermal and electric loads is an important criterion in evaluating cogeneration potential. The size of the loads dictates the types of cogeneration technologies (described in Appendix B) that could be employed. As discussed below, the most economical approach is generally to install cogeneration capacity to supply less than the peak demand in order to keep the cogeneration equipment operating for as many hours as possible.

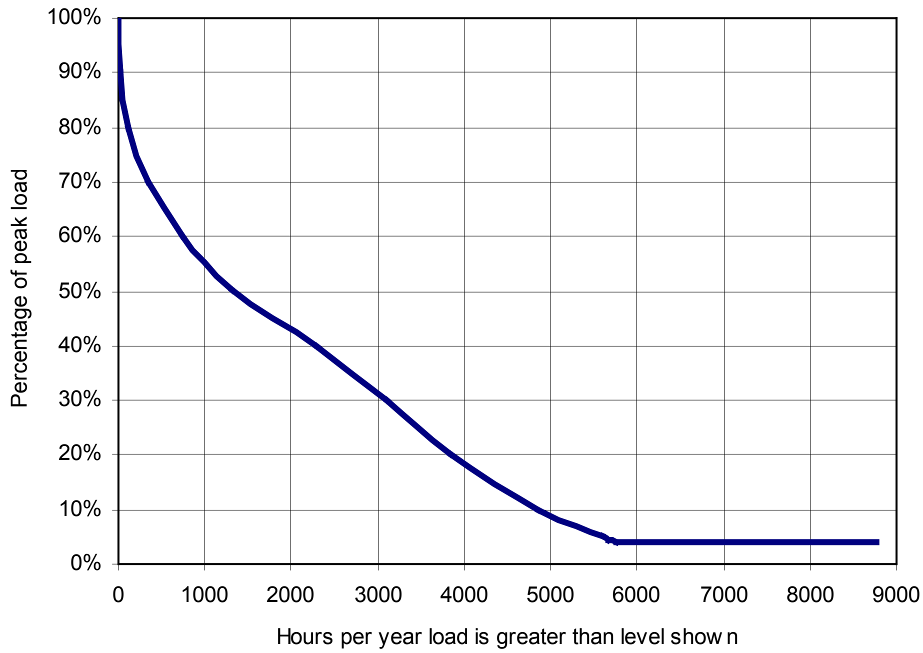
2.3 Thermal and electric load factors

The Equivalent Full Load Hours (EFLH) is an important factor in evaluating cogeneration possibilities. The EFLH is the ratio of the annual energy compared to the peak demand times 8,760 (the number of hours in a year). High electric and thermal EFLH increases the feasibility of cogeneration.

An economically ideal thermal load would be independent of the weather and would be the same year-round. However, loads in the real world are not ideal. A thermal load duration curve of the thermal load is a valuable asset in analyzing cogeneration. Such a curve plots the number of hours per year in which the load is greater than a given percentage of the peak load. Illustrative load duration curves may help to explain how cogeneration units can be sized economically.

Figure 2.1 shows an illustrative load duration curve for space heating and domestic hot water loads. If a cogeneration facility was sized to provide 100% of the peak load, the equipment would be operating at far less than its capacity for most of the year. The load factor for this curve is about 23 percent. The load factor is determined by dividing the actual EFLH (in this case approximately 2,000) by the total number of hours in a year or 8,760.

Figure 2.1
Illustrative Load Duration Curve for Space Heating and Domestic Hot Water



Figures 2.2 and 2.3 show illustrative load curves for hypothetical industrial loads. Figure 2.2 represents a thermal load with 4,000 EFLH, and Figure 2.3 represents a thermal load with 6,500 EFLH. A cogeneration facility sized to provide 50% of the peak thermal demand would have a load factor of about 75% for the load illustrated in Figure 2.2, and about 95% capacity factor for the load illustrated in Figure 2.3.

Figure 2.2
Illustrative Load Duration Curve for Hypothetical Industrial Facility #1

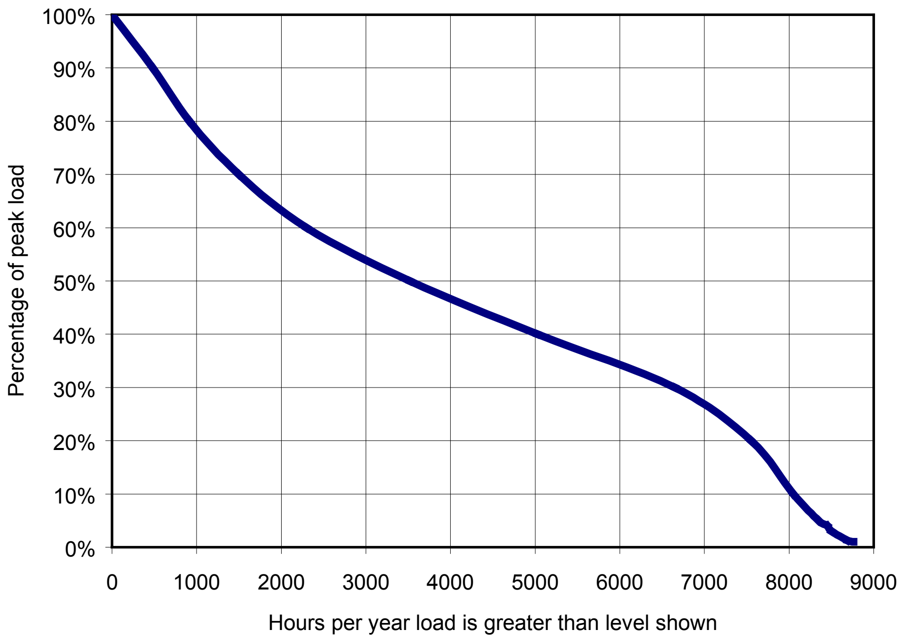
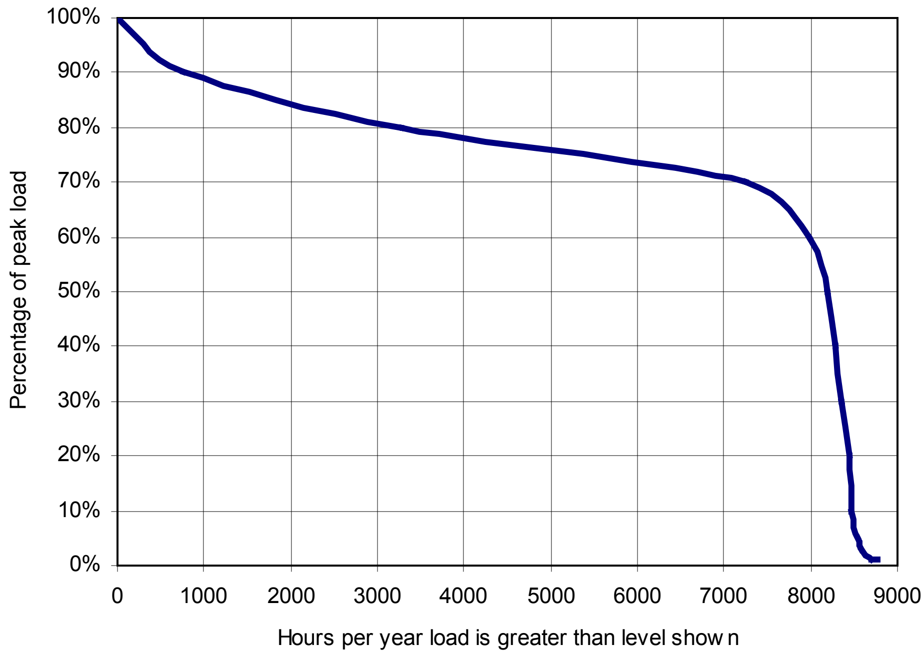


Figure 2.3
Illustrative Load Duration Curve for Hypothetical Industrial Facility #2



If the power generation component of the cogeneration cycle is designed to supply the maximum thermal energy load, the incremental cost of the generator may not be justified by value of the relatively small amount of power cogenerated within the peaking segment of the thermal load duration curve. A smaller cogeneration facility sized to deliver a portion of the thermal energy at a very high load factor could be more economical. The thermal and power loads should be in reasonable synchronization. If they are not, a market for excess power produced or a resource to secure cogenerated power shortfall must be secured. If the cogenerating power resource is to supply a given electric load without an adequate thermal load, a method to dispose of the excess thermal energy must be available. An automatic extraction pressure, condensing steam turbine generator would fulfill this need.

2.4 Age of Existing Thermal Facilities

The age of existing thermal equipment and plans for replacement or additional capacity are important considerations in determining the feasibility of adding cogeneration. Advanced age can mean poor reliability and high maintenance costs, making new equipment a more attractive option to increase reliability and reduce maintenance costs. The ideal times for considering cogeneration are when a new thermal intensive plant is to be constructed, or when existing thermal energy resources are to be replaced. If a potential cogenerator has reliable, reasonably efficient and low cost thermal and power resources that supply the loads, it may be difficult to replace these resources economically given the significant capital investment requirement.

2.5 Avoided Costs and Potential Revenue

The value of the cogenerated electric energy is an important component in evaluating a cogeneration project. This is the value of displaced purchased energy and the revenue from the sale of excess power produced. Low values reduce the economic viability of cogeneration.

The economics of combustion turbine cogeneration based on current prices of power and natural gas are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no incentive to design the facility to generate more power than needed on site if the excess power cannot be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become more attractive.

Investment tax credit. Tax credits for investments in cogeneration facilities have been approved by Congress. Generally, the investment tax credit (ITC) proposals would provide a 10% investment tax credit for qualifying facilities. This kind of tax credit would be an incentive to facilities to install cogeneration because it would reduce the payback time by years in some cases.

Production tax credit. Production tax credits (PTC) for production of electricity using biomass materials are currently under consideration in Congress. The proposals would extend the current production tax credit until 2011, with a credit per kWh indexed to inflation. The current credit is 1.7 cents per kWh. If this credit were available, it would drop the payback time on any facility burning biomass.

2.6 Fuel Supply Availability and Cost

The availability and cost of fuel for a cogeneration project are critical factors. As natural gas prices have increased, gas-fired cogeneration becomes less attractive, because the cogenerated power will tend to be relatively more expensive compared to power purchased from a utility using coal and nuclear sources. Although natural gas has tended to be the fuel of choice for many cogeneration projects, other fuels may actually make a project more economical.

2.7 Environmental Benefits

Figure 2.4 compares the efficiency of a representative cogeneration system to current average U.S. power plants and to various new power-only technologies.

The efficiency of cogeneration, and the emission characteristics of gas-fired generation compared to the mix of existing power plants, results in significant environmental benefits. Figure 4.2 compares the emissions of a 7.35 MW gas-fired combustion turbine (from Chippewa Valley Ethanol, Option 2 as described in Chapter 5) to emissions from:

- Purchased power was assumed to be generated by major intermediate load plants operated by Xcel Energy[1] (A.S. King, Black Dog, High Bridge and Riverside plants); and
- Thermal energy was assumed to be generated with Boiler emissions from gas-fired boilers assumed to operate at 82% efficiency.

The data are summarized in Appendix I.

Figure 2.4
Efficiency of Cogeneration Compared to Power-Only Technologies

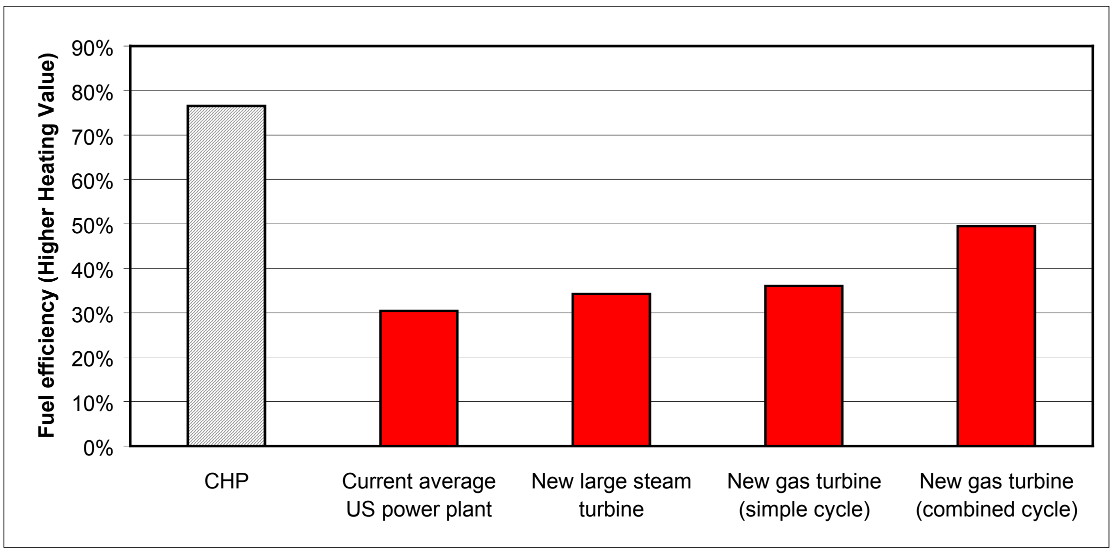


Figure 2.5
Cogeneration Emissions Compared to Local Intermediate Load Power Plants

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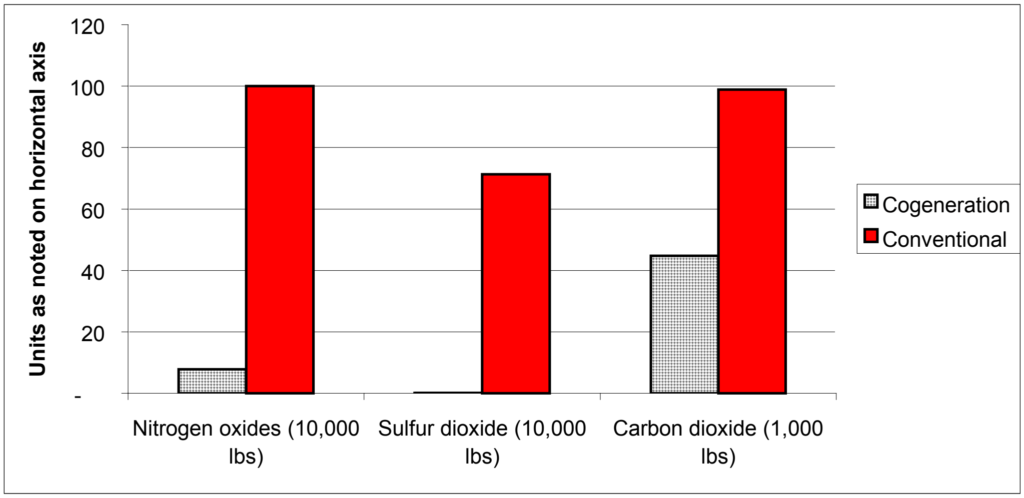
[1] Per 1990 emissions data provided to the Minnesota Pollution Control Agency.
[13] "The Market and Technical Potential for Combined Heat and power in the Commercial/Institutional Sector" Revision 1, Jan. 2000.



2.8 Summary

In summary, cogeneration is most likely to be cost-effective when the following factors are present:

- A large, high load factor thermal load.
- A large, high load factor power load.
- Relatively high cost electric power resources.
- A cost-effective supply of electricity to back up and augment cogeneration when necessary.
- A relatively high-value market for excess power generation, net of transmission and distribution costs.
- The opportunity to re-dedicate the cost of replacing existing thermal resources to the cost of a new cogeneration project.
- The opportunity to use lower-cost fuels with cogeneration compared to current fuels for thermal production.
- Acceptable environmental impacts of cogeneration, such that the project can be meet all regulatory hurdles in a timely and cost-effective way.

Based on screening analysis of the survey results, this study ranks cogeneration prospects:

3. The Survey

3.1 Chapter Overview

This chapter describes the energy user survey undertaken to identify potential cogeneration sites, including the data and analysis used to identify survey recipients and the process for conducting the survey.

Many large industrial facilities already operate cogeneration systems. For example, in the paper industry, Blandin Paper (Grand Rapids), Boise Cascade (International Falls), Potlatch (Bemidji) and Champion International (Sartell) operate cogeneration systems. In the mining industry, Cyprus Minerals Company in Silver Bay has a cogeneration system. Other industrial cogeneration systems include United Defense (Fridley), Archer Daniels Midland (Mankato), Quadrant Corp. (Perham) and L.S. Power (Cottage Grove). A cogeneration project had been planned for Koch Refinery, using petroleum coke byproduct as a fuel. This would have been a very large project (200-250 MW). Koch was able to negotiate attractive power rates and has, at least temporarily, abandoned the project.[2]

A number of district heating systems have cogeneration facilities, including public utilities in Willmar, Hibbing, Virginia and New Ulm, and the University of Minnesota in Minneapolis. District Energy St. Paul Inc. is a private, non-profit utility that currently operates a 860 kW backpressure cogeneration system and is now designing a 25 MW waste-wood-fired cogeneration facility. Franklin Heating Station in Rochester, which supplies Mayo Clinic and other buildings in Rochester, also uses cogeneration.

3.2 Identification of Survey Recipients

The Minnesota Pollution Control Agency (MPCA) maintains a database on Minnesota facilities that have boiler permits from the MPCA. The MPCA boiler database records the type and quantities of fuel consumed at each site in 1998. Fuel consumption data were converted to show total million Btu (MMBtu) at each site using the conversion factors shown in Appendix C.

Total reported fuel use in 1998 was 556,207,000 MMBtuat 552 sites. Most of this fuel use occurs at the 164 facilities consuming over 100,000 MMBtu per year. These large facilities represented 98% of the total energy use. Seventeen power plants are responsible for 77% of total fuel consumption.

Excluding power plants, total fuel consumption in 1998 was 126,785,000 MMBtu at 536 sites. Non-power-plant fuel users consuming over 100,000 MMBtu were targeted for the survey. These users had a total 1998 fuel use of 118,367,000 MMBTU, or 93 percent of the non-power plant fuel use.

Some of the non-utility sites using more than 100,000 MMBtu were eliminated as survey targets because they were known to already be operating cogeneration facilities. The resulting list of 142 targeted fuel users had a total 1998 fuel use of 109,155,000

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[2] "Opportunities to Expand Cogeneration in Minnesota," Center for Energy and Environment.

MMBTU, or 86 percent of non-utility fuel consumption. Information on these users, ranked by fuel consumption, is summarized in Appendix E.

This non-power-utility fuel use is broken down by sector, using Standard Industrial Classification (SIC) codes, in Table 3.1. The number of sites and average fuel use per site is also shown.

Table 3.1
Fuel Consumption by Sector, Excluding Power Plants

SIC	SIC Industry Category	Total Energy (MMBTU)	Number of Sites	Average energy per site (MMBTU)
10	Metal mining	10,738,566	4	2,684,641
20	Food and kindred products	27,926,297	30	930,877
24	Lumber and wood products	10,357,125	11	941,557
26	Paper and allied products	25,705,154	7	3,672,165
27	Printing and publishing	253,299	1	253,299
28	Chemicals and allied products	7,687,691	11	698,881
29	Petroleum and coal products	1,946,612	5	389,322
32	Stone, clay, glass, and concrete products	2,558,856	3	852,952
33	Primary metal industries	1,118,715	2	559,358
34	Fabricated metal products	661,871	4	165,468
35	Industrial machinery and equipment	610,536	2	305,268
36	Electrical and electronic equipment	408,981	2	204,491
37	Transportation equipment	611,699	1	611,699
38	Instruments and related products	166,441	1	166,441
39	Miscellaneous manufacturing industries	212,173	1	212,173
45	Transportation by air	409,254	1	409,254
49	Electric, gas, and sanitary services	11,111,121	11	1,010,102
51	Wholesale trade--nondurable goods	112,180	1	112,180
80	Health services	1,195,658	6	199,276
82	Educational services	4,974,586	10	497,459
87	Engineering and management services	1,596,696	1	1,596,696
92	Justice, public order, and safety	627,063	1	627,063
UN	Unassigned SIC Numbers	7,376,210	32	230,507
	Total	118,366,782	148	799,776

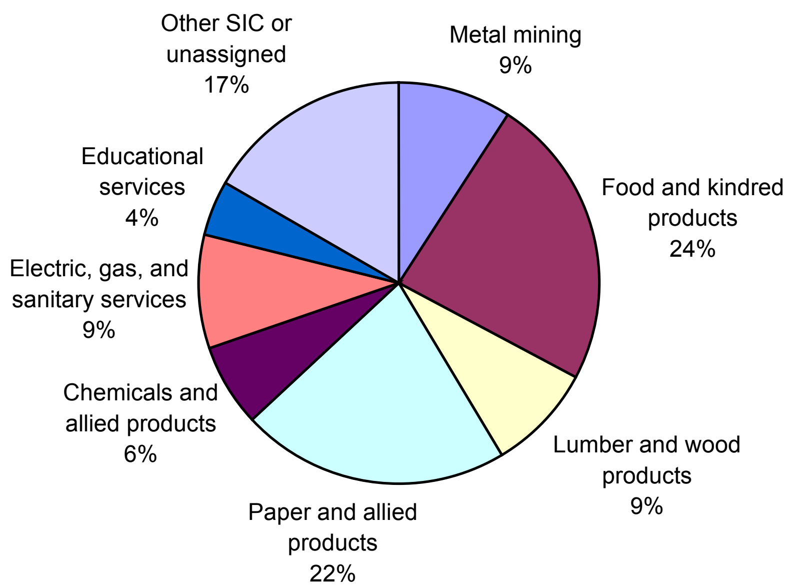
A graphical representation of fuel use by sector is shown in Figure 3.1. Seven sectors are responsible for 83% of the total non-power-utility fuel use:

- Metal mining

- Food and kindred products
- Lumber and wood products
- Paper and allied products
- Chemicals and allied products
- Electric, gas, and sanitary services
- Educational services

Of these, sectors with particularly high fuel use per site include mining, paper and electric, gas and sanitary services. This last category includes district heating facilities and other facilities where in some cases power is generated.

Figure 3.1
Fuel Consumption by Major Sectors Excluding Power Plants (1998)



3.3 Conducting the Survey

A survey form was developed and tested on a sample of ten recipients to determine if potential respondents are able and willing to provide the desired data, and to ensure that survey responses produce the information necessary to evaluate cogeneration potential. A copy of the survey form is included in Appendix F. No changes to the survey form were required based on the test activity, so the survey, with a cover letter, was sent to the 142 targeted fuel users (Appendix E). Telephone follow-up was conducted with 63 recipients.

3.4 Survey Return

Thirty two recipients responded to the survey, for a response rate of 23%. Survey respondents represented a total of 38,713,000 MMBtu of fuel consumption, equal to 31% of the total non-utility fuel use. The survey respondents were fairly evenly distributed relative to facility size.

Data on all fuel users and the relationship of the survey recipients to the total user population is summarized in Table 3.2. Data collected in the survey are summarized in Appendix G. Analysis and discussion of these data are presented in Chapter 4.

Table 3.2
Summary of 1998 Fuel Consumption Data

Fuel Consumption (MMBtu)	**All facilities**	**% of total**
Total	556,206,707	100%
Facilities over 100,000 MMBtu/year	547,788,903	98%
Facilities under 100,000 MMBtu/year	8,417,804	2%
Total non-utility (MMBtu/year)	126,784,586	23%
Number of sites		
Total	552	100%
Facilities over 100,000 MMBtu/year	164	30%
Facilities under 100,000 MMBtu/year	388	70%
Non-utility facilities	536	97%
Survey recipients	142	26%
Survey respondents	32	6%
Average fuel consumption per site (MMBtu)		
Average – All facilities	1,007,621	
Facilities over 100,000 MMBtu/year	3,340,176	
Facilities under 100,000 MMBtu/year	21,695	
Non-utility facilities	236,538	
Survey recipients	763,319	
Survey respondents	1,209,775	

4. Analysis of Survey Information

4.1 Selected Facilities

Of the thirty-two facilities that responded, four sites were judged to have high cogeneration potential and ten sites were judged to have some cogeneration potential based on the data available. The analysis below describes what the survey found with regard to these fourteen sites. The fourteen sites are listed in Table 4.1.

4.2 Survey Results

The size and load factor of the thermal and electric loads are shown in Table 4.1 Two of the sites have very large power demands (70 MW and 90 MW), while seven of the sites have a demand less than 5 MW, and the remaining five sites range from 6 MW to 19 MW. For three of the sites, no information was available for the peak thermal demand.

Table 4.1
Summary of Selected Screening Parameters for 14 Sites

Site #	Site	Peak Power Demand MW	Electric Load Factor EFLH	Peak thermal Demand MMBTU/Hr	Thermal Load Factor EFLH	Average Load Ratio (Elec/Therm)	Total 1998 fuel use (MMBtu)
1	Blandin Energy Center	90.0	8,096	890	4,096	N/A	5,957,718
2	Boise Cascade	70.0	7,571	1,800	6,111	0.16	7,871,515
3	Hormel Foods Corp	19.0	5,789	160	N/A	N/A	540,813
4	Potlatch Corporation	13.0	8,478	N/A	N/A	0.33	1,519,452
5	Rahr Malting Co	12.4	5,242	160	6,666	0.21	1,055,021
6	Seneca Food Corp -- Glencoe	9.7	1,876	90	982	0.70	99,729
7	Marvin Windows and Doors	6.4	3,281	33	5,988	0.36	146,152
8	Seneca Foods Corp -- Rochester	4.6	1,983	182	N/A	N/A	149,557
9	St. Olaf College	3.8	4,474	N/A	N/A	N/A	147,869
10	SMDC Health Systems	3.4	4,118	36	3,889	0.34	159,303
11	Chippewa Valley Ethanol	3.4	6,000	110	5,323	0.12	740,990
12	Ridgewater College	1.7	2,508	N/A	N/A	0.66	278,146
13	Diamond Brands	1.6	5,764	20	7,662	0.21	212,173

14	Duluth Steam Cooperative	0.8	3,196	270	3,147	0.01	991,740

Figure 4.1 illustrates the electricity Equivalent Full Load Hours (EFLH) for the 14 sites. EFLH is the ratio of the annual energy compared to the peak demand times 8,760 hours in a year. Figure 4.2 illustrates the thermal EFLH for the sites (some sites did not provide sufficient data to calculate thermal EFLH). High electric and thermal EFLH increase the feasibility of cogeneration.

Figure 4.1
Electricity Equivalent Full Load Hours

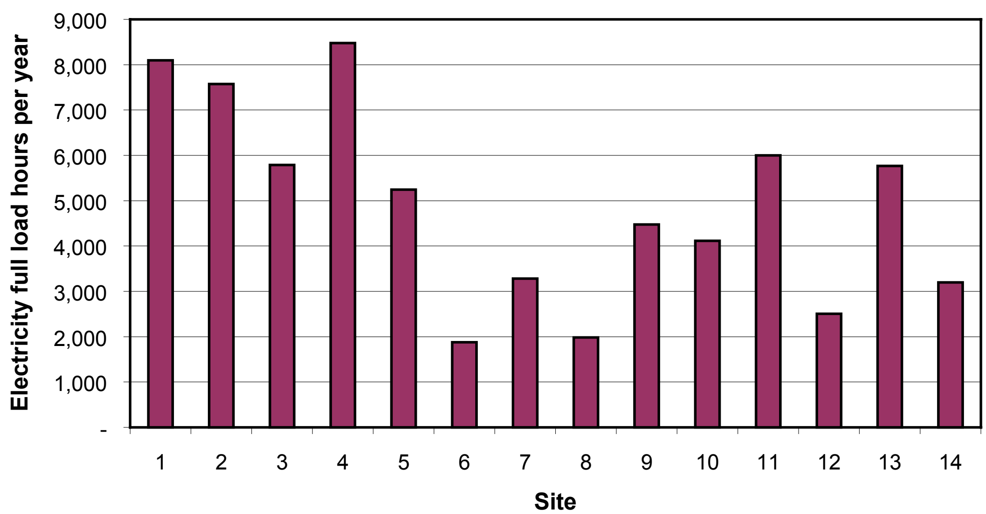
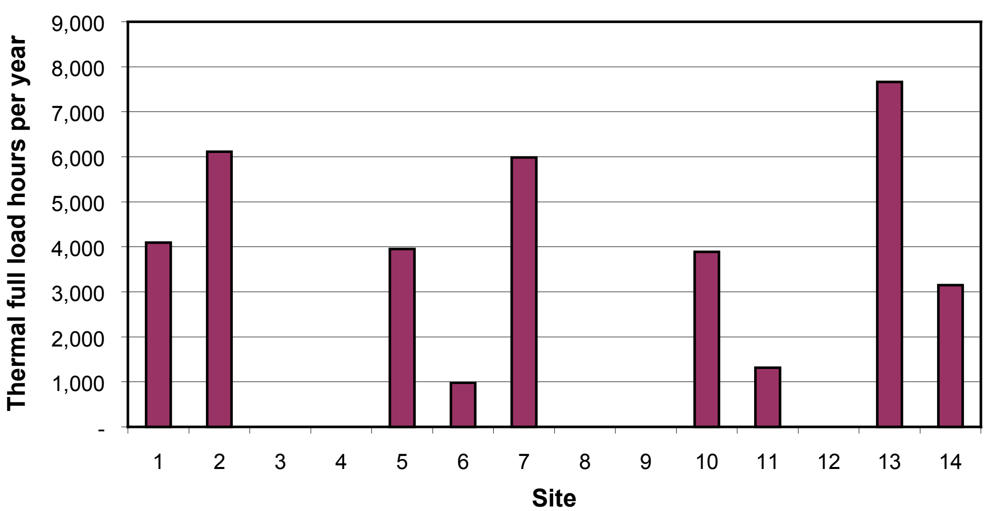


Figure 4.2
Thermal Equivalent Full Load Hours



4.4 Potential for Cogeneration in Minnesota

Based on screening analysis of the survey results, this study ranks cogeneration prospects:

Good prospects, with good data

- Rahr Malting Co (Shakopee)
- Chippewa Valley Ethanol Company (Benson)
- St. Mary's Duluth Clinic (SMDC) Health Systems (Duluth)
- Duluth Steam Cooperative (Duluth)

Potential prospect, but data are inadequate for assessment.

- Seneca Foods Corp. (Rochester)
- Hormel Foods Corp. (Austin)
- St Olaf College (Northfield)
- Crown Cork & Seal (Faribault)
- Froedtert Malt (Winona)
- Dairy Farmers of America (Zumbrota)
- Heartland Corn Products (Winthrop)
- US Steel - Minnesota Ore Operations (Mountain Iron)
- Potlatch Corporation (Brainerd) Already has small cogeneration but thermal and power loads may support more; data are incomplete.
- Boise Cascade (International Falls)– has existing cogeneration but is considering more; key cost data are considered proprietary.

Already have cogeneration, and prospects for additional economical cogeneration is unlikely

- American Crystal Sugar (Crookston)
- American Crystal Sugar (East Grand Forks)
- American Crystal Sugar (Moorhead)
- Order of St Benedict Inc. St Johns University (Collegeville)
- New Ulm Public Utilities (New Ulm)
- Blandin Energy Center (Grand Rapids)

Poor prospects

- Ford Motor Company (St. Paul) Large hydroelectric capacity and poor thermal load factor makes this a poor prospect for cogeneration.
- Louisiana Pacific Corporation (Two Harbors) Wide mix of process requirements and equipment, and access to inexpensive wood fuel and relatively small size for solid fuel cogeneration makes this a difficult prospect for cogeneration.
- Seneca Food Corp (Glencoe) Low load factors make this a poor prospect for cogeneration.
- Ridgewater College (Willmar) Small size makes this a poor prospect, data are incomplete.

- Diamond Brands Inc. (Cloquet) Access to inexpensive wood fuel makes this a poor prospect for cogeneration.
- Interplastic Corp. (Minneapolis) Wide mix of process requirements and poor electric load factor makes this a difficult prospect for cogeneration.
- Fergus Falls Regional Treatment Center (Fergus Falls) Small size and outside purchase of steam makes this a poor prospect, and data are incomplete.
- Northwood Panelboard (Solway) Access to inexpensive wood fuel makes this a difficult prospect for cogeneration.
- North Star Steel (St. Paul) Direct-fired processes eliminates this as a cogeneration prospect.
- Brown Printing Co. (Waseca) Direct-fired processes eliminates this as a cogeneration prospect.
- Marvin Windows and Doors (Warroad) Low cost power makes this a poor prospect for cogeneration.
- Brainerd Regional Human Services (Brainerd) Small size and existing back-up generation makes this a poor prospect; data are incomplete.
- Ag Processing Inc. (Dawson) Small size makes this a poor prospect, data are incomplete.

5. Site Specific Analysis

Of the four sites determined to have good potential for cogeneration, three were analyzed in further detail to get a better idea of the appropriate technology and size and economic viability for each facility.

Preliminary evaluations of the economic feasibility of cogeneration were performed for selected sites. Key tasks in the analysis include:

- Analysis of the present systems for production or purchase of electric and thermal energy and a review of the pertinent costs.
- Identify potentially feasible cogeneration technologies and fuels, and outline a proposed method of operation for the cogeneration system.
- Analyze the operating costs of appropriately sized cogeneration systems, and the resulting net operating cost savings.
- Estimate the capital costs for the cogeneration system.
- Compare the capital costs to the net cost savings to estimate a simple payback.

The following site assessments are very preliminary. Further site analysis would address the following questions:

- What are the detailed provisions of the existing contracts for purchased electric power and fuel, particularly the impact of demand charges?
- What are the costs of standby electric power and electric energy to augment or replace the cogeneration cycle operation during scheduled or forced outages?
- Is the prospect confronted with replacing existing resources due to age, obsolescence, high O&M costs, or unacceptable reliability?
- Are there better data on the efficiency of current fuel use?
- Is the prospect expanding its facility such that it will require increased thermal or electric energy?
- What is the available space within or adjacent to the plant to locate new facilities?
- What are the environmental impacts of cogeneration and what are the related regulatory hurdles?
- What are the costs of implementing cogeneration considering all site-specific factors?
- What is the cogeneration power output considering the impact of ambient temperatures on combustion turbine efficiency?
- What are the opportunities for excess power sales and pricing?

5.1 Rahr Malting Company – Shakopee

This large grain processing plant consumes 1,185,000 thousand cubic feet (mcf) of natural gas and 65,000 Mwh of electric energy annually. The maximum demand for electricity is 12.4 MegaWatts (MW). The current peak demand for thermal energy is 250-300 mmBTU/hour; however, the company is considering process modifications that would reduce the peak demand to 160 mmBTU/hour. Based on the data submitted for the survey, the annual thermal and electric EFLH are 6,666 hours and 5,242 hours, respectively.

The thermal energy produced in this plant is used in the processing and drying of grain. Drying is done in several kilns using hot air produced with indirect gas-fired air heaters or in heat exchangers with a thermal fluid heated to 240°F with gas. If the fluid were to be heated with steam, the steam conditions would be about 15 psig, dry and saturated, assuming a heat exchanger terminal difference of 10°F.

No process steam is currently generated in the plant. The total electric and thermal requirements suggest a good potential for cogeneration. The dispersed use of thermal energy around the plant site in the present plant configuration is not conducive to supply thermal energy from a single cogeneration facility. However, the company is investigating a plan to develop a thermal distribution system around the manufacturing area that could be served from a central cogeneration plant. Scheduling of thermal energy required by the kilns could reduce peak thermal demand, but the annual process thermal energy requirements would not change. The plant operates 24 hours/day and 7 days/week and does not shut down.

The thermal and electric loads with the upgraded thermal system projected by the company and used as the basis for this analysis are as follows:

Peak Loads		
	Thermal	160 MMBtu/hour
	Electric	12.4 MW total, about 10.0 MW without seasonal chiller load
Annual energy		
	Thermal	1,066,500 MMBtu
	Electric	65,000 MWh
Average Loads		
	Thermal	122 MMBtu/hr
	Electric	7.4 MW

Following the plant improvements, the peak power-to-heat ratio will be 0.26 and the average power-to-heat ratio will be 0.21.

Electric power is purchased for $0.045/Kwh including demand and energy charges. . Recent natural gas costs have been $5.00/MMBtu. There are 2-3 acres available adjacent to the plant for new facilitiesThe facility produces about 58,000 tons per year of biomass by-product that has a fuel value of 7,943 Btu/lb.

Two cogeneration cycles previously outlined were studied for Site 5: a steam boiler with back-pressure steam turbine-generator; and a combustion turbine with a heat recovery steam generator (HRSG).

5.1.1 Option 1 -- Steam Boiler with Back-Pressure Steam Turbine Generator

Of the cogeneration technologies described in Appendix B, a steam turbine generator is of greatest interest because it would provide an opportunity to use biomass fuel produced at the facility site. The company is investigating the availability and use of its plant residue as boiler fuel. This residue consists of grain hulls, chaff and other materials.

Given the size of the required cogeneration, and the ratio of thermal load to electric load, a backpressure steam turbine generator is most appropriate. The turbine-generator would run only to the extent that a thermal load is available. Thus, the electric output of the turbine would be wholly dependent on steam load. The company states that the electric and thermal loads are well synchronized. However, there will be times when these loads are not synchronized, i.e. when the turbine-generator will not produce enough electricity to meet the load. Under the configuration described below, the interconnection with the utility must be retained as a standby electric resource and to augment turbine generator output, or potentially provide an outlet for excess electric energy cogeneration when the respective loads are not synchronized.

A preliminary plant design and a detailed plant heat balance would be necessary for a precise evaluation. However, this preliminary investigation can suggest the economic feasibility of the project. Appropriate design conditions are 600 psig, 750°F steam to the turbine throttle, exhausting to a backpressure of 50 pounds per square inch gage (psig). To supply the 160 MMBtu/hour peak thermal demand would require an estimated 167,000 lbs/hour of steam. Supplying this peak thermal load plus steam for the feedwater heating cycle requires an estimated boiler output of 187,000 lbs/hr. The turbine generator would cogenerate a gross electric output of 9308 kW or 8377 kW net assuming 10% station power (power required within the power plant itself).

The economic analysis assumes operation for 6,300 equivilent full-load hours (EFLH). Total fuel requirements would be 1,537,500 MMBtu per year, of which about 60% could be provided from in-house biomass by-products. The remaining fuel requirement would have to be obtained from the surrounding agricultural area.

The biomass-fired cogeneration facility would generate 81% of power requirements and almost all thermal requirements. No excess power is assumed to be generated and sold to the grid. Purchased power needed to meet the facilities full power requirements was assumed to be 20% more costly per kWh than current power purchases. This rough assumption was made because a relatively few kWh of electricity would be purchased compared with the peak electricity capacity required. In other words, the demand charges per kWh would be higher than under current purchase conditions.

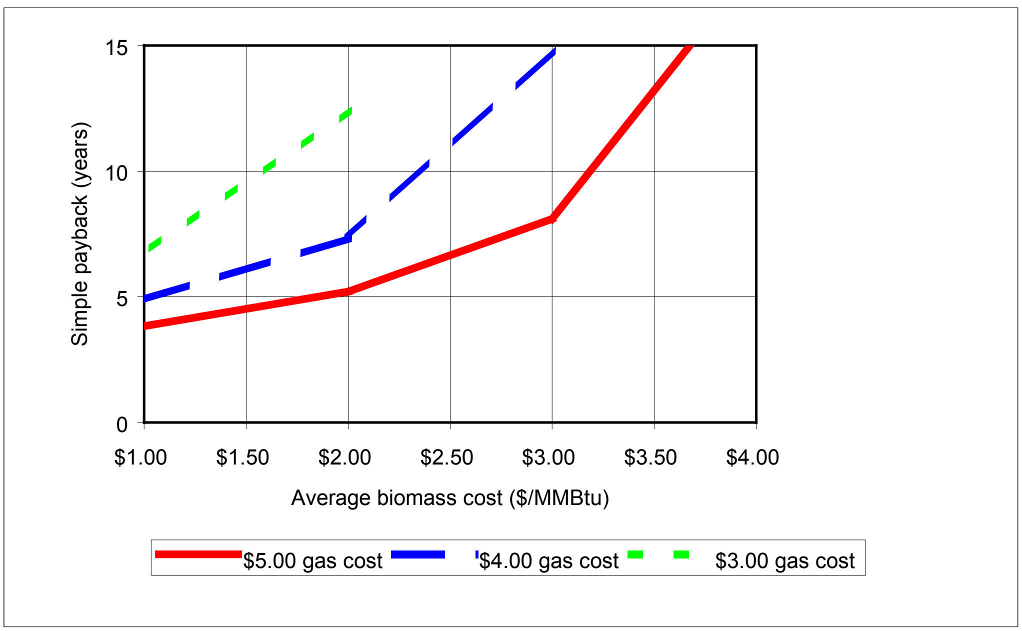
The economic analysis is presented in Appendix H-1. The capital and operating cost estimates were prepared without a detailed plant design and should be viewed as preliminary estimates only. A capital cost of $2,400/kWh of gross power generation capacity is assumed, including boiler, turbine-generator, biomass fuel handling, electrical equipment and a small peaking/back-up boiler. Operating costs include fuel, labor (8

Full-Time-Equivalents or FTE) and $0.014/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of $0.045/kWh and avoided fuel costs of $5.00/MMBtu, simple payback ranges from 18.3 years to 6.7 years for a range of assumed average biomass costs of $4.00 to $1.00 per MMBtu, as illustrated in Figure 5.1. Payback times increase as shown if the avoided natural gas is assumed to be purchased at $4.00 and $3.00 per MMBtu. The impact is stronger as the assumption of the biomass fuel cost increases. There is no payback at $4.00/MMBtu biomass costs for the $4.00 gas price scenario, and no payback at $3.00/MMBtu biomass costs for the $3.00 and $4.00 gas price scenarios.

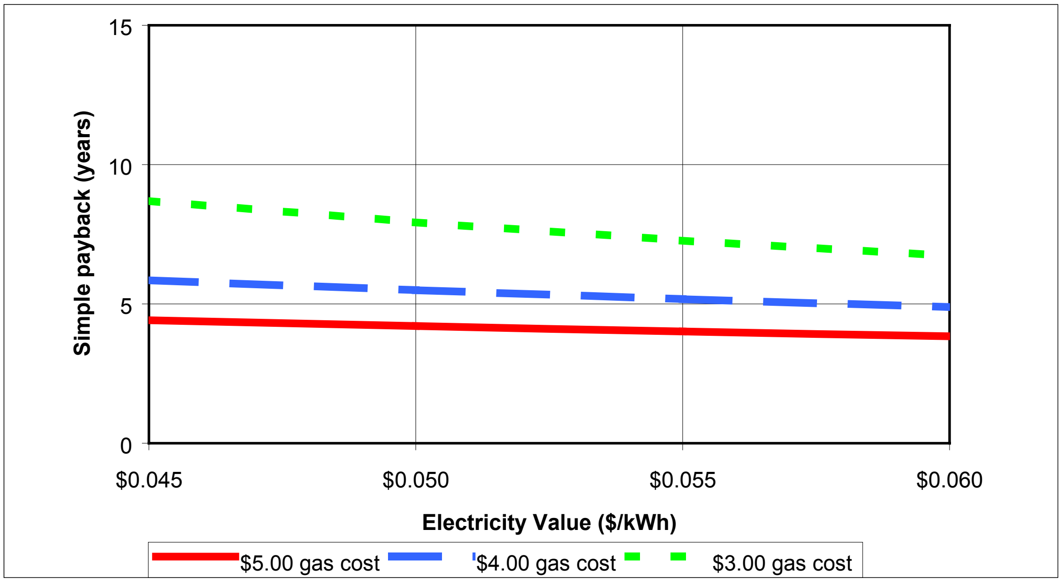
The results are very sensitive to the cost of biomass fuel. If a relatively low fuel cost can be achieved (less than $1.50/MMBtu), a simple payback of less than five years appears possible, assuming an offset natural gas price of $5.00/MMBtu.

Figure 5.1
Steam Turbine Sensitivity to Biomass Fuel Costs at Current Avoided Power and Fuel Costs (Base Case)



Because of the enormous impact of the cogeneration fuel cost and thermal energy production avoided costs, the results are relatively insensitive to the value of avoided power purchases. Figure 5.2 shows the simple payback results across a power value range of $0.045-0.060/kWh, assuming a fuel cost of $1.50/MMBtu.

Figure 5.2
Steam Turbine Sensitivity to Avoided Power Costs at Biomass Cost of $1.50/MMBtu (Base Case)



Two policies could improve the economic feasibility: potential investment tax credits and potential production tax credits.

Investment tax credit. Tax credits for investments in cogeneration facilities are currently under consideration in Congress. Generally, the investment tax credit (ITC) proposals would provide a 10% investment tax credit for qualifying facilities. This drops the payback time by 0.4 to 1.2 years compared to the base case, over the range of $5.00 to $3.00/MMBtu in avoided gas costs, assuming relatively inexpensive biomass fuel ($1.00-$2.00/MMBtu).

Production tax credit. Production tax credits (PTC) for production of electricity using biomass materials such as contemplated in this analysis are currently under consideration in Congress. The proposals would extend the current production tax credit until 2011, with a credit per kWh indexed to inflation. The current credit is 1.7 cents per kWh. If this credit was available, it would drop the payback time by 0.5 to 4.1 years compared to the base case, over the range of $5.00 to $3.00/MMBtu in avoided gas costs, assuming relatively inexpensive biomass fuel ($1.00-$2.00/MMBtu).

Combining the investment tax credit and production tax credits brings the simple payback down to 3.0 years assuming $5.00/MMBtu avoided gas costs and $1.00/MMBtu biomass fuel cost. Paybacks are under 5 years for a wider range of circumstances, as illustrated in Figures 5.3 and 5.4.

Figure 5.3
Steam Turbine Sensitivity to Biomass Fuel Costs at Current Avoided Power and Fuel Costs (with Tax Credits)

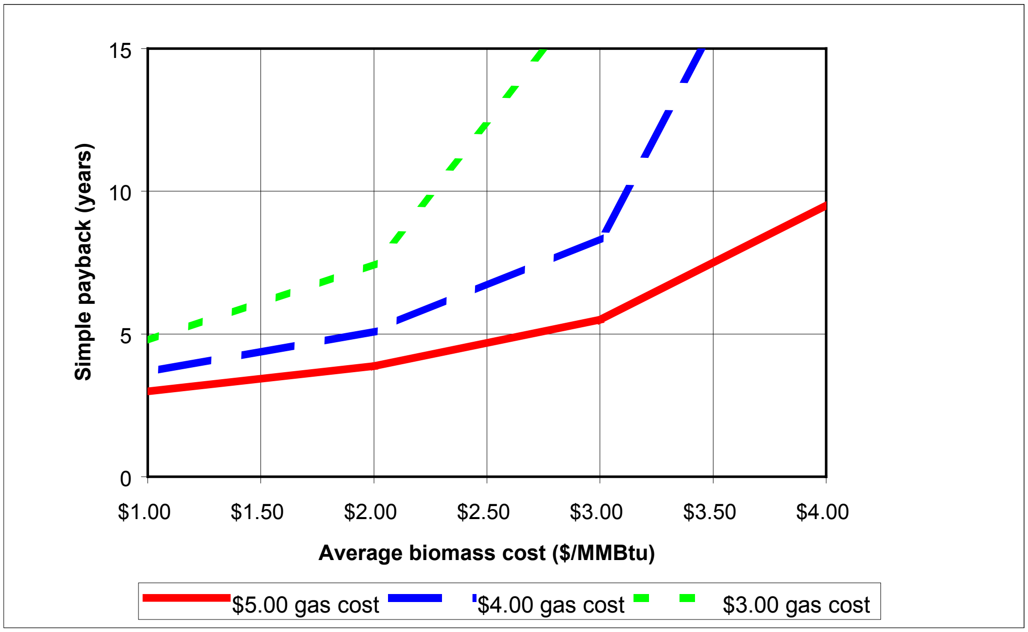
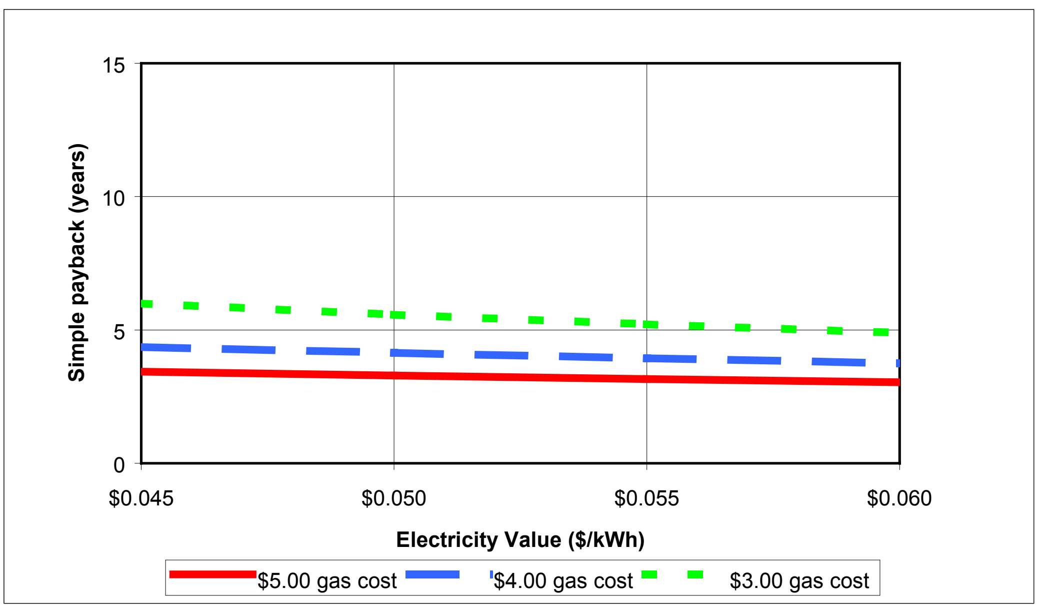


Figure 5.4
Steam Turbine Sensitivity to Avoided Power Costs at Biomass Cost of $1.50/MMBtu (with Tax Credits)



Methods to Increase Electric Output. The electric output of the plant can be increased by raising the turbine throttle steam conditions above 600 psig - 750°F. As an example, raising the conditions to 850 psig - 900°F would increase gross electric output by an estimated 20-25%. With these higher steam conditions, high pressure/temperature parts of the turbine, boiler, piping, etc. require higher cost materials. Additional power could be produced, but the marginal boiler plant cost should be compared with the value of an increase in avoided power purchase costs.

Another method of increasing electric output would be to install a controlled extraction pressure/condensing steam turbine generator. In this configuration, 50 psig process steam is extracted from the turbine at controlled quantity and pressure to supply process needs similar to the exhaust from the back pressure turbine in the previous scenario. Steam also flows to the surface condenser serving the turbine. This allows generation of electric energy on a condensing cycle independently of the process steam requirement. As in the case of the back pressure unit, when the steam extracted from the turbine would generate electric energy greater than plant requirements, some method of marketing the excess or bypassing steam around the turbine would be necessary. When the converse is true and cogenerated electric energy is less than plant load, condensing cycle generation can make up the shortfall by increasing steam flow to the condenser.

The marginal capital costs for this option are greater than for the back pressure turbine option because this option requires:

- higher cost turbine-generator;
- larger boiler and associated auxiliaries;
- added costs for condensing cycle equipment including condenser, cooling tower(s), circulating water pumps and electric service to cooling tower fans and condensate pumps; and
- higher costs for mechanical work including boiler feedwater pumps, feedwater heaters, steam and water piping.

Unless current pricing conditions change it is unlikely to make economic sense to design the facility to generate additional power.

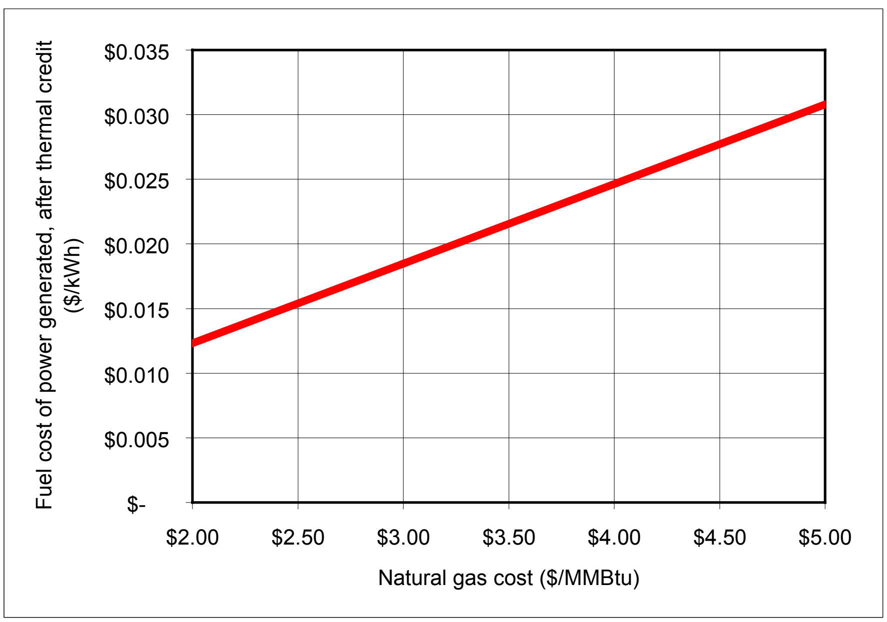
<u>Conclusion</u>
In conclusion, sizing the facility to generate 9.3 MW gross power output is potentially feasible if sufficient biomass fuel can be procured at a low cost. If the cost of biomass fuel averages less than $1.50/MMBtu, and assuming that the cost of offset natural gas consumption is at current high levels ($5.00/MMBtu) and the cost of offset power costs is at current levels ($0.045/kWh), the preliminary economic analysis indicates a simple payback less than 5 years. This payback increases to 5.9 and 8.7 years if the cost of offset gas is assumed to be $4.00 and $3.00, respectively. Investment tax credits and/or production tax credits would make a significant difference in meeting likely financial performance criteria. This would yield simple paybacks less than 5 years even with offset gas assumed to cost up to about $4.50/MMBtu.

5.1.2 -- Combustion Turbine with Heat Recovery Steam Generator
An alternative to the steam turbine cogeneration would be a combustion gas turbine with a Heat Recovery Steam Generator (HRSG). An appropriately sized gas turbine, rated 10,439 kW at ISO conditions (see glossary) was chosen. Air temperature is most critical as gas turbine output decreases with increases in the compressor inlet air temperature. Output during warm weather can be improved with inlet air cooling.

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 48,600 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 106 mmBTU/hr, the steam production increases to 150,000 lbs/hr. The turbine-generator would cogenerate a gross electric output of 10.44 MW or 9.92 MW net assuming 5% station power (power required within the power plant itself).

For this site, the thermal load factor of 76% (6,666 EFLH) is greater than the electric load factor of 60% (5,242 EFLH). The operation of the unit will be limited by power load rather than thermal load, unless excess power can be sold at a price greater than the marginal cost of producing the power. It is unlikely that sufficient revenue could be obtained for excess power exported to the grid. Under current conditions, revenue per kWh would probably not exceed $0.015/kWh for electric energy. In order to realize more revenue from power sales, a capacity commitment would have to be made. Figure 5.5 shows the fuel cost of a representative small turbine-generator used for cogeneration.

Figure 5.5
Fuel Cost per kWh in Small Combustion Turbine Cogeneration

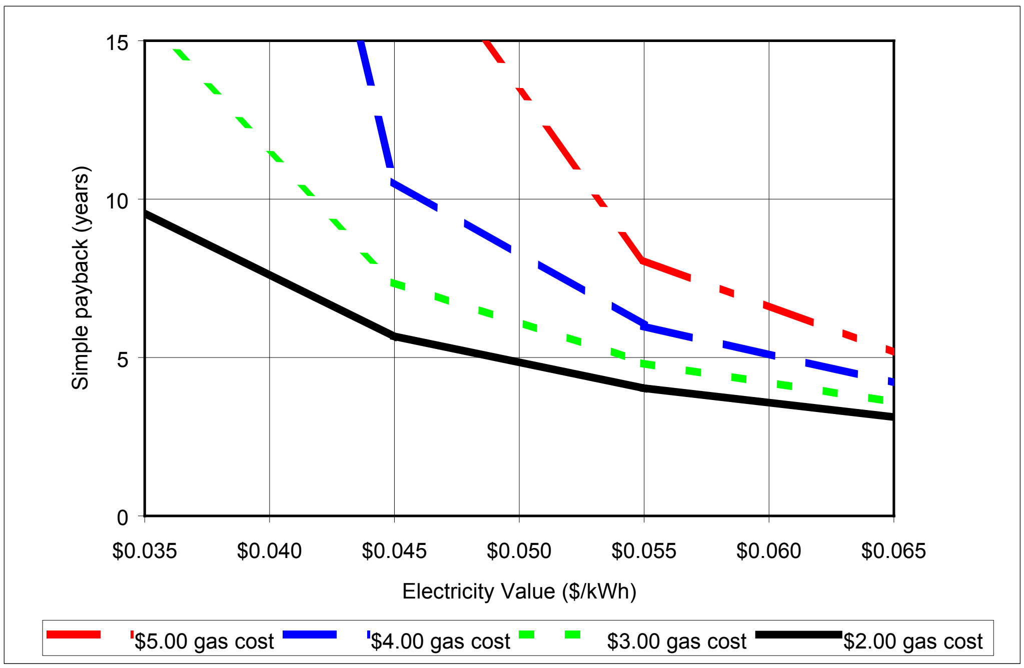


The economic analysis assumes a thermal load factor of 6,350 EFLH. Total fuel requirements would be 1,417,000 MMBtu per year. The cogeneration facility would generate 97% of power requirements and 89% of thermal requirements. No excess power is assumed to be generated and sold to the grid. We assume that the power required to be purchased would be 20% more costly per kWh than current power purchases.

The economic analysis is presented in Appendix H-2. A capital cost of $840/kWh of gross power generation capacity is assumed, including additional boiler capacity to provide thermal capacity not provided with cogeneration (it is unlikely that existing thermal equipment could be re-used with the new central thermal loop). Operating costs include fuel, labor (4 FTE, to provide licensed operators whereas current staff does not include any licensed operators) and \$0.0054/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of \$0.045/kWh, simple payback ranges from 19 years to 6 years for a range of natural gas costs of \$5.00 to \$2.00 per mmBTU. Payback periods drop dramatically if the assumed avoided power cost increases. At \$0.065/kWh, payback ranges from 3.1 years (assuming \$2.00/MMBtuMMBtugas) to 5.1 years (assuming \$5.00/MMBtugas). Sensitivity of payback to the variables is illustrated in Figure 5.6.

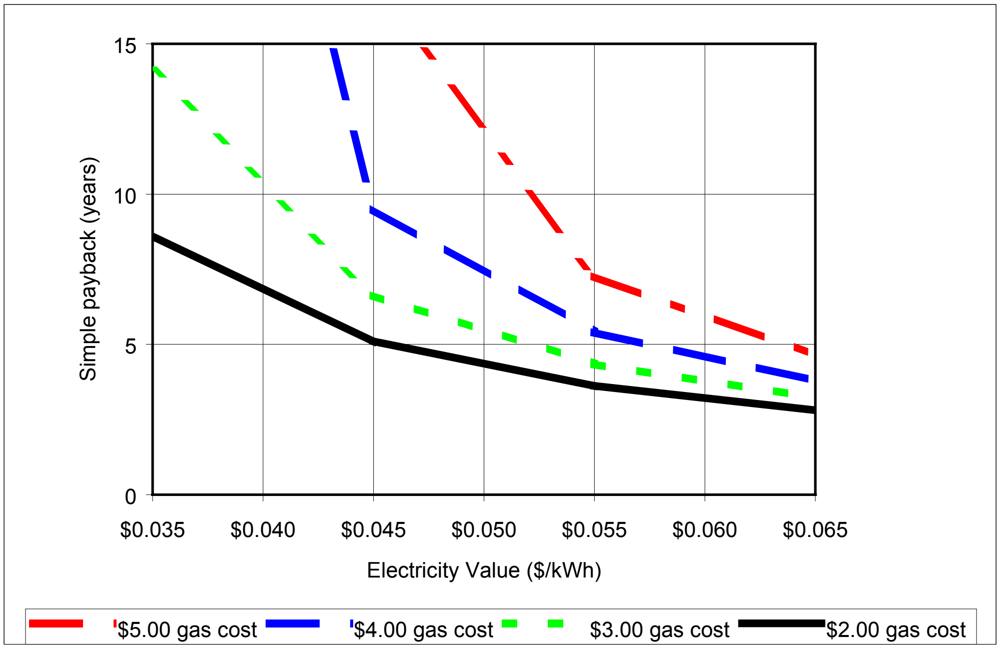
Figure 5.6
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.5 to 4.4 years depending on assumed natural gas costs and power values. Resulting payback times are illustrated in Figure 5.7.

This option is not cost-effective under current avoided fuel and power costs. Even assuming natural gas costs \$3.00/MMBtu, the simple payback exceeds 5 years unless the avoided power cost is assumed to be about 10% higher than currently (\$0.050/kWh rather than \$0.045/kWh). Power costs would have to go up considerably, while gas prices would have to remain fairly low, in order for this option to be feasible.

Figure 5.7
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (with Investment Tax Credit)



5.2 Chippewa Valley Ethanol Company – Benson

This ethanol plant consumes 725,000 thousand cubic feet (mcf) of natural gas, 75,000 gallons of propane (about 6,860 mmBTU) and 20,400 Mwh of electric energy annually. The maximum demand for electricity is 3.4 MegaWatts (MW). The current peak demand for thermal energy is 110 mmBTU/hour. Based on the data submitted for the survey, the annual thermal and electric EFLH are 5,600 and 6,000, respectively. About 60% of the fuel is used to generate steam, with the remaining 40% in direct-fired dryers.

The plant has two 1,500 HP boilers, each 60,000 lbs/hour of 65 psig, 315°F steam. One boiler is 1 year old and the other is 4.5 years old. Boiler efficiency ranges from 83-84% (HHV).

The plant also has two 4.5-year-old 1,500 kW diesel engines, with no heat recovery, generating 450 MWH annually. These engines are run during power curtailment periods (about a dozen days per year for 4-6 hours each time) and to ensure power reliability during storms.

The plant operates year-round. The company is currently studying the potential to increase plant production by up to 125%. The plant currently has enough steam generation capacity for a plant production increase of 100%.

The thermal and electric loads used as the basis for this analysis are as follows:

Peak Loads		
	Total Thermal	110 mmBTU/hour
	Steam Thermal	65 mmBTU/hour
	Electric	3.4 MW
Annual energy		
	Total Thermal	611,106 mmBTU
	Steam Thermal	397,219 mmBTU
	Electric	20,400 MWh
Average Loads		
	Total Thermal	70 mmBTU/hr
	Steam Thermal	45 mmBTU/hr
	Electric	2.3 MW

Power costs are \$0.025/kWh energy charge, plus \$6.20/kW/month demand charge up to 2,500 kW. The average power cost about \$0.036/kWh. This power cost is kept low because the facility agrees to be curtailed (using their back-up generation) during high-demand periods.

The ratio of average electric load to average steam thermal load is 0.12, appropriate for a combustion turbine with a heat recovery steam generator (HRSG).

It is important to note that, in addition to the options presented below, an even more attractive alternative would be to obtain cogenerated thermal energy from the biomass-fired power plant that is being planned for implementation near this site. However, not enough is known about this plant to adequately assess the feasibility of this alternative.

5.2.1 Option 1 – Small Combustion Turbine with Heat Recovery Steam Generator

A gas turbine sized for the thermal load (and assuming no power export to the grid) is rated 3.42 MW at ISO conditions was chosen. The turbine-generator would cogenerate a net electric output of 3.25 MW net, assuming 5% station power (power required within the power plant itself).

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 17,900 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 25.8 mmBTU/hr, the steam production increases to 43,100 lbs/hr. The temperature of the exhaust gas is increased from 915°F to 1400°F, which is the supplemental firing temperature recommended by manufacturers.

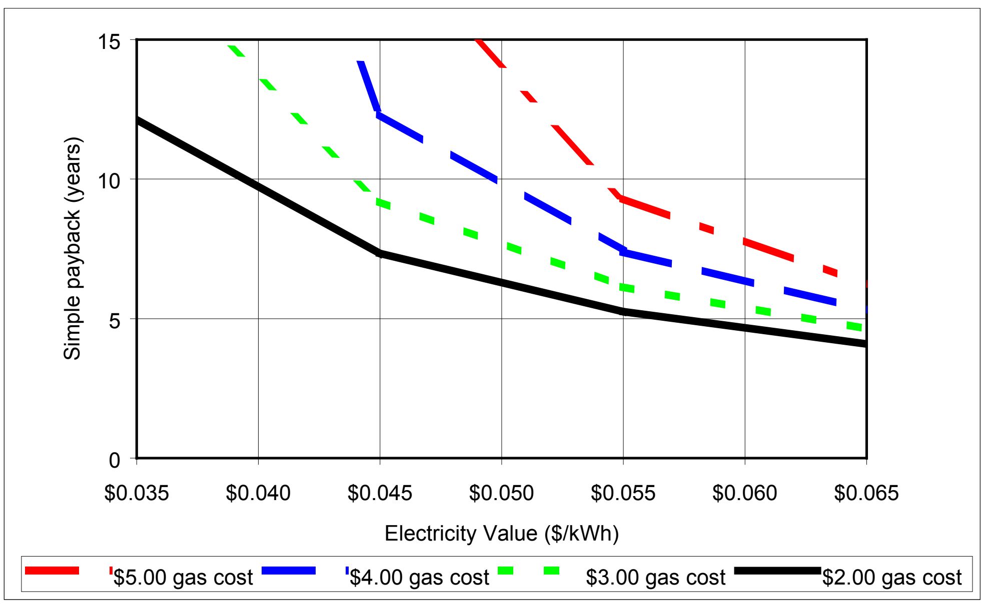
For this site, the steam thermal load factor (6,100 EFLH) is only slightly greater than the electric load factor (6,000 EFLH). For this option it is assumed that the operation of the unit will be limited by power load rather than thermal load, unless excess power can be sold at a price greater than the marginal cost of producing the power, as discussed above under Site 5, Option 2.

The economic analysis assumes operation for 6,250 EFLH. Total fuel requirements would be 522,775 MMBtu per year. The cogeneration facility would generate nearly 100% of power requirements and 88% of thermal requirements. No excess power is assumed to be generated and sold to the grid.

The economic analysis is presented in Appendix H-3. A capital cost of $1,100/kWh of gross power generation capacity is assumed. Operating costs include fuel, labor (1 FTE in addition to licensed engineers already on site) and $0.007/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

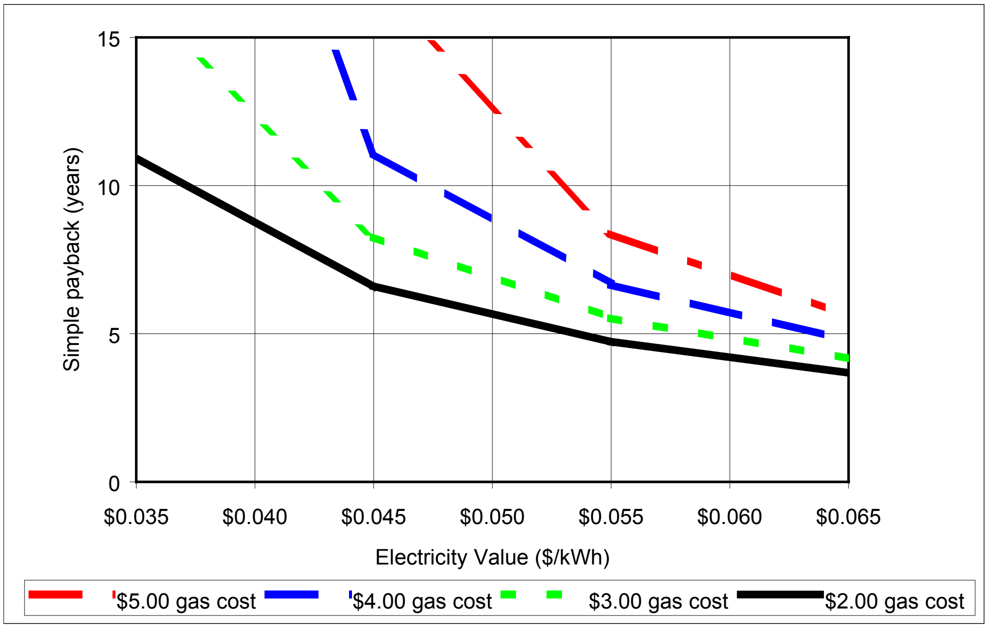
With avoided power costs of $0.036/kWh, simple payback exceeds 12 years, even with natural gas costs as low as $2.00 per MMBtu, as illustrated in Figure 5.8. Payback periods drop dramatically if the assumed avoided power cost increases. At $0.065/kWh, payback ranges from 4.1 years (assuming $2.00/MMBtu gas) to 6.2 years (assuming $5.00/MMBtu gas).

Figure 5.8
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.5 to 3.7 years depending on assumed natural gas costs and power values. Resulting payback times are illustrated in Figure 5.9.

Figure 5.9
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (with Investment Tax Credit)



5.2.2 Option 2 – Larger Combustion Turbine with Sale of Excess Power to the Grid

A larger gas turbine was selected to follow the thermal load. The turbine-generator would cogenerate a gross electric output of 7.35MW or 6.98 MW net at ISO conditions, assuming 5% station power (power required within the power plant itself). In this scenario, a significant amount of excess power is generated and is assumed to be sold as discussed below.

At ISO conditions this unit would supply exhaust heat to a HRSG to produce 31,200 lbs/hr of 125 psig dry and saturated steam. With maximum supplemental fuel firing of 31.8 mmBTU/hr, the steam production increases to 62,400 lbs/hr.

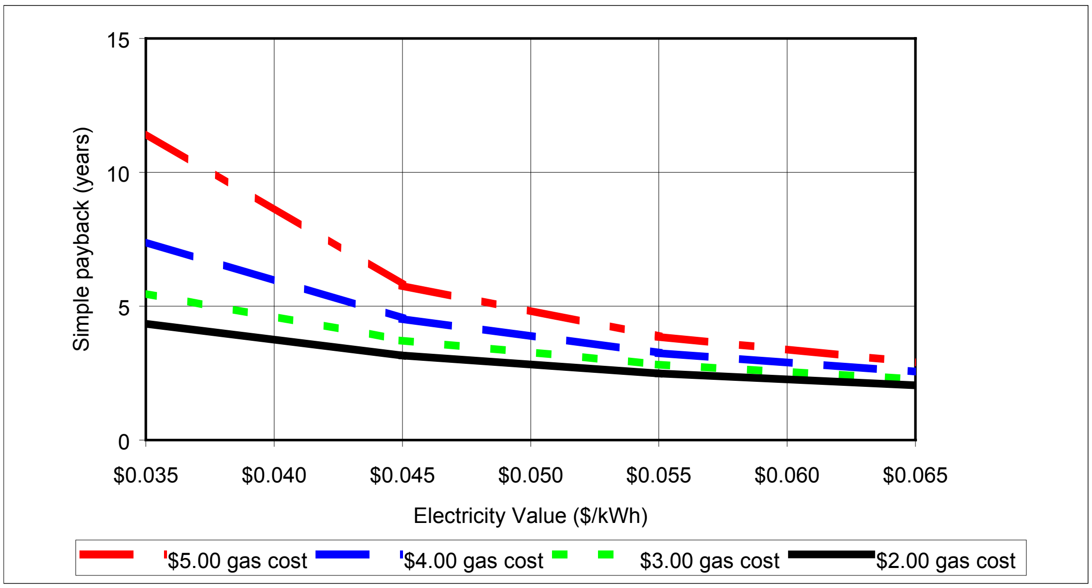
For this option it is assumed that the operation of the unit will be limited by thermal load and that power can be sold at a price greater than or equal to the marginal cost of producing the power. Two power sale price scenarios are examined. In the base case scenario it is assumed that power is sold for $15/MWH. Later, we assume net metering, i.e., power sold to the grid is priced at the same cost as power purchased.

The economic analysis assumes operation for 8,059 EFLH (electric), with supplemental firing according to thermal demand. Total fuel requirements would be 783,884 MMBtuper year. The cogeneration facility would generate nearly 100% of power requirements plus nearly 36,000 MWH for sale and 64% of thermal requirements.

The economic analysis is presented in Appendix H-4. A capital cost of $890/kWh of gross power generation capacity is assumed. Operating costs include fuel, labor (1 FTE in addition to licensed engineers already on site) and \$0.0058/kWh for maintenance and other non-fuel, non-labor operating costs such as water and chemicals.

With avoided power costs of \$0.035/kWh and assuming excess power is sold for \$15/MWH, simple payback ranges from 11.5 years to 4.3 years for a range of natural gas costs of \$5.00 to \$2.00 per mmBTU, as illustrated in Figure 5.10. Payback periods drop dramatically if the assumed avoided power cost increases. At \$0.065/kWh, payback ranges from 2.0 years (assuming \$2.00/MMBtugas) to 2.9 years (assuming \$5.00/MMBtugas).

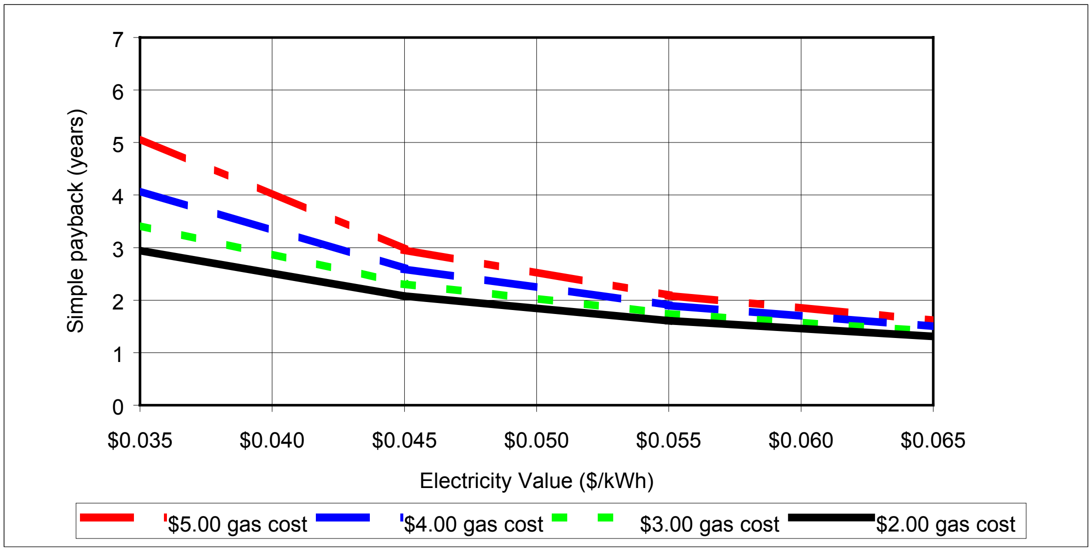
Figure 5.10
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs



With a 10% Investment Tax Credit, payback times would decrease by 0.2 to 1.1 years depending on assumed natural gas costs and power values.

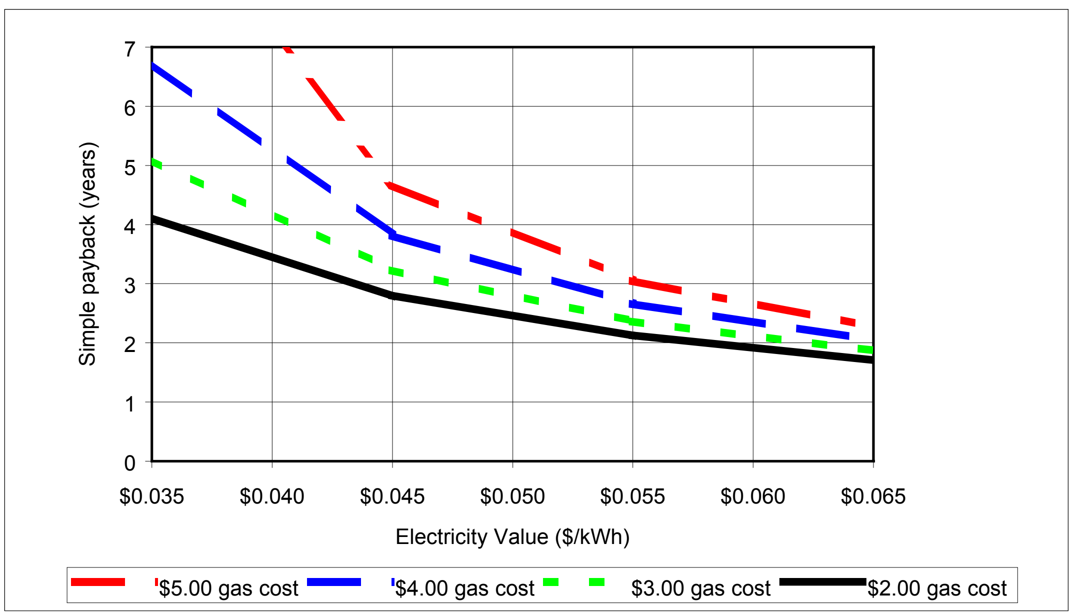
If net metering is assumed, i.e., utility purchase of excess power generation at the same price as the average cost for the facility to purchase power, the economics become very attractive, as illustrated in Figure 5.11.

Figure 5.11
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (assumes Net Metering at 100% of average purchase price)



If it is assumed that the utility purchases power at only 50% of the facility's average purchase costs, the paybacks increase but are still very attractive (Figure 5.12).

Figure 5.12
Combustion Turbine Sensitivity to Avoided Power Costs at Range of Gas Costs (assumes Net Metering at 50% of average purchase price)



5.3 Duluth Steam Cooperative

This plant supplies 160 psig steam to a district heating system serving 225 buildings in the core area of the city. The system has no condensate return lines. The plant has four coal-fired boilers each rated 100,000 lbs/hr which generate steam at 225 psig, dry and saturated. Export steam is reduced to 160 psig with pressure reducing facilities. The boilers are 68 years old, but have been well maintained. In anticipation of adapting the plant for cogeneration, the boilers were successfully pressure tested at the original design pressure of 400 psig and would operate at the pressure in the cogeneration cycle. The current plant fuel is western coal costing $1.30 per MMBtu.

The peak steam generation is 225,000 lbs/hr and steam sales are in the range of 301,000 to 317,000 Mlbs/year. A current study is analyzing the economic and technical feasibility of installing a district cooling system to serve a group of government buildings, using steam-driven absorption chillers. This would increase the summer load on the system and increase the thermal load factor and improve the cogeneration potential.

A 950 kW gas-fired internal combustion engine in the plant provides standby power and eliminates the demand charge from the cost of purchased power, resulting in a cost of $0.038/kWh for purchased power.

The cogeneration system envisioned would require installation of two back-pressure steam turbine-generators rated 295 kW and 627 kW, with throttle steam flows of 33,000 and 64,000 lbs/hr, respectively. The turbines would be supplied with 400 psig, dry and saturated, steam and exhaust at 160 psig. These turbines would be operated singly or in tandem to serve the high load factor segments of the load pattern during the minimum, shoulder and peak heating periods.

The turbine generators would exhaust to the high load factor segment of the steam load pattern and generate approximately 4,408 MWH/year. This output would supplant the 2,122 MWH of plant electric service now purchased, plus 2,285 MWH for sale. The value of this energy plus additional revenue from the sale of reserve power capacity as estimated by the local utility would increase revenues by an estimated $170,000. The estimated marginal operating expenses attributable to cogeneration would be $54,000 (largely due to increasing steam pressure to 400 psig), resulting in $116,000 in operating income available for debt service with no margin for profit or return on investment. The estimated capital cost of the project is $1,217,000. With a preliminary simple payback estimate of 10.5 years, pursuing this project at this time is subject to the investment policies of the owner.

An important advantage of this plant is that it is coal-fired at a low cost per MMBtu. The increasing cost of retail natural gas could result in incremental steam sales for the district heating system, which could enhance the economics of cogeneration.

In addition to the steam district heating system, the owners recently established a district hot water distribution system to supply the thermal requirements of large hotels near the steam plant. These requirements include heat for room and hallway heating, domestic water heating, pools and spas. The hot water is generated with steam/water heat exchangers in the plant and is used in plate heat exchangers at the customer premises to produce the on-site thermal requirements. These customers have 147 and 102 rooms respectively with the latter soon to be expanded to 170 rooms. The domestic hot water needs are large especially during the summer months, which will improve the load factor on the district heating plant and enhance the cogeneration potential.

6 Potential for New Cogeneration

It is not possible to provide a solid quantification of technical or economic potential of new cogeneration in Minnesota based on the data obtained in the survey. However, a rough estimate of the technical potential, based on extrapolation from the survey data, indicates a technical potential of 1,600 to 2,100 MW of new cogeneration. This estimate takes into account the power and thermal demand characteristics of the survey respondents and the relationship of these demands to fuel use, and applies these to the total fuel use by facilities reporting over 100,000 MMBtu per year fuel consumption to the MPCA. Generally cogeneration facilities serving these users would have a power generation capacity exceeding 1 MW. Another study by Kattner/FVB District Energy, focusing on small energy users, estimated technical potential for small cogeneration (under 1 MW) in commercial buildings[13]. In that study, the technical potential in Minnesota for under 1 MW was estimated to be 842 MW.

Quantification of the economic potential for cogeneration is an even more challenging task – one that is beyond the scope of this report. However, some qualitative conclusions can be drawn based on the case study analyses described in Chapter 5.

Preliminary economic analyses of cogeneration were prepared at three sites:

- Rahr Malting, Site 5 – Two options were examined: 9.3 MW steam turbine cogeneration fueled with biomass; and a 10.4 MW combustion turbine fueled with natural gas.
- Chippewa Valley Ethanol, Site 11 – Two options were examined: 3.4 MW and 7.4 MW combustion turbines fueled with natural gas.
- Duluth Steam Cooperative, Site 14 – Two small backpressure steam turbines, totaling 0.9 MW, added to an existing coal-fired boiler facility.

Generally, combustion turbines were determined to be the appropriate cogeneration technology based on the power-to-heat ratios, level of the electric and thermal output requirements and in some cases the temperature requirements of the thermal end-uses.

The preliminary evaluation of the biomass cogeneration option at Rahr Malting indicates that this approach can be feasible if biomass fuel is available at an average cost below $1.50/MMBtu. In cases where the facility is generating a significant portion of the required biomass material, this may be achievable.

The economics of combustion turbine cogeneration based on current prices of power and natural gas are generally not attractive if the facility is sized and operated to offset only purchased power. This design constraint is realistic given the current regulatory and pricing framework for sale of excess power, i.e., there is no incentive to design the facility to generate more power than needed on site if the excess power can't be sold at a sufficient price. However, if the excess power can be sold for a significant percentage of the power purchase price, with the cogeneration facility sized and operated consistent with the thermal load, the economics of combustion turbine cogeneration become more attractive.

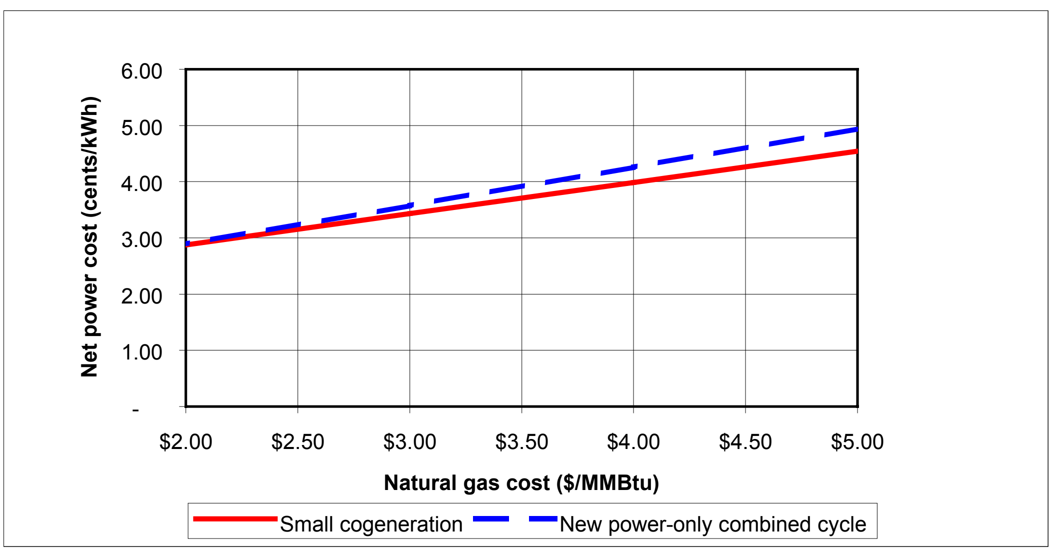
From a public policy standpoint, it is appropriate to ask how the total net economics of power generation with cogeneration compare to the total net economics of non-cogeneration power plants. Although this was not within the scope of this study, one indicative analysis was undertaken as described below.

Small power generation facilities generally require higher capital costs per unit of power output than the large combustion turbine combined cycle facilities likely to be built to provide new power generation capacity. On the other hand, cogeneration provides economies by recovering the waste heat. How do the economics of a small cogeneration facility compare with a large combined cycle non-cogeneration power plant, including debt service, fuel and operating costs? Appendix H-4 presents the total economics, including debt service, of the 7.35 MW facility analyzed for one of the sites evaluated in Chapter 5. Appendix J presents the total economics for a new 260 MW power-only combined cycle power plant.

The analysis indicates that at $2.00/MMBtunatural gas, the net costs of power from a small combustion turbine cogeneration facility are about the same as that from a large new non-cogeneration combined cycle facility. As gas costs increase, cogeneration gains an increasing economic advantage.

This simplified comparative analysis suggests that in addition to providing significant efficiency and environmental benefits, the overall cost of cogeneration compares favorably with new non-cogeneration power plants.

Figure 4.3
Net Power Costs for 7.35 MW Cogeneration Compared to 260 MW Non-Cogeneration Gas Turbine Combined Cycle



Appendix A: Definitions

Term	Abbreviation	Definition
Acid dew point		The temperature in an exhaust stack where the exhaust gases will start to condense into an acidic liquid.
Aero-derivative		This refers to a combustion turbine that was originally designed for aircraft propulsion and has been adapted for use as a stationary power generation source.
Combined Heat and Power	CHP	Combined Heat and Power (CHP), also known as cogeneration, is the simultaneous production of electrical energy and useful thermal energy from a single energy source. A CHP system most commonly utilizes a combustion turbine, steam turbine or reciprocating engine that converts chemical energy into electrical power and useful thermal energy such as steam, hot water, or high temperature gases used in direct-drying industrial processes.
Combined cycle		A thermodynamic cycle that utilizes a combustion turbine to produce steam that in turn is used to drive a steam turbine.
Condensing power plant		An electrical generation facility where the exhaust steam from a steam turbine generator is routed through a condenser where it is condensed and reused in the thermal cycle.
Cyclones		A separator that uses centrigugal forces to remove particulate from combustion gasses.
Diesel engine		A type of reciprocating engine where the fuel is ignited by compression and heat.
District heating		A heating system utilizing either steam or hot water produced in a central plant and distributed to individual buildings via a networked piping system.
Equivalent full load hours	EFLH	The total amount of energy consumed annually divided by the peak hour energy consumption
Fuel cell		A device that utilizes fuel in a chemical reaction to produce electricity similar in nature to a battery.

Gas turbine		A turbine that uses combustion of either gas or liquid fuel as the motive force in rotating an electric generator
Generator		An electro-mechanical device that converts mechanical energy into electrical energy.
Heat Recovery Steam Generator	HRSG	A heat transfer device that transfers heat from a combustion turbine exhaust and produces either hot water or steam.
Higher Heating Value	HHV	This is the heating value of a fuel assuming that water vapor is condensed in the combustion gas mixture.
Intercooler		A heat exchanger located between compressor stages to lower the temperature of the air for improving the output of an engine.
ISO Conditions	ISO	Standard atmospheric conditions of 59 °F (15°C), 60% relative humidity and 14.7 psia (1013 mbar) atmospheric pressure. Established by the International Standards Organization
Lbs/ sq. in absolute	psia	This is a unit of pressure based on an absolute scale where 0 is a perfect vacuum.
Lbs/ sq. in gauge	psig	This is a unit of pressure based on a gauge scale where 0 is atmospheric pressure.
Load factor		This is the EFLH divided by the total number of hours in a year (8,760).
Millibar	mbar	This unit of pressure is equal to 0.01450377 psi
Otto engine		A type of reciprocating engine where the fuel is ignited by a spark.
Reciprocating engine		An internal combustion engine that utilizes either gas or liquid fuel. When the fuel is combusted in the combustion chamber a piston is forced to drive a crank shaft.
Simple cycle		A combustion turbine operating without heat recovery typically used for peaking service.
Steam turbine		A turbine that uses high pressure and high temperature steam as the motive force in rotating an electric generator
Textile baghouse		A type of combustion gas cleaning process where the gasses are routed through textile filter bags to remove particulate.

Appendix B: Cogeneration Technologies

B.1 Introduction

This chapter describes cogeneration technologies. This section has been adapted with permission from a report prepared for International Energy Association,[3] with updating from additional sources. Key terms are defined in Appendix A.

All efficiency calculations are based on the Lower Heating Value (LHV) of fuels. In the discussions of simple cycle and combined cycle gas turbine technologies, performance is based on International Standards Organization (ISO) conditions. ISO conditions are listed in appendix A. In addition, the pressure drop at the intake and at the outlet were each assumed to be 4 inches of water.

B.2 Gas Turbines

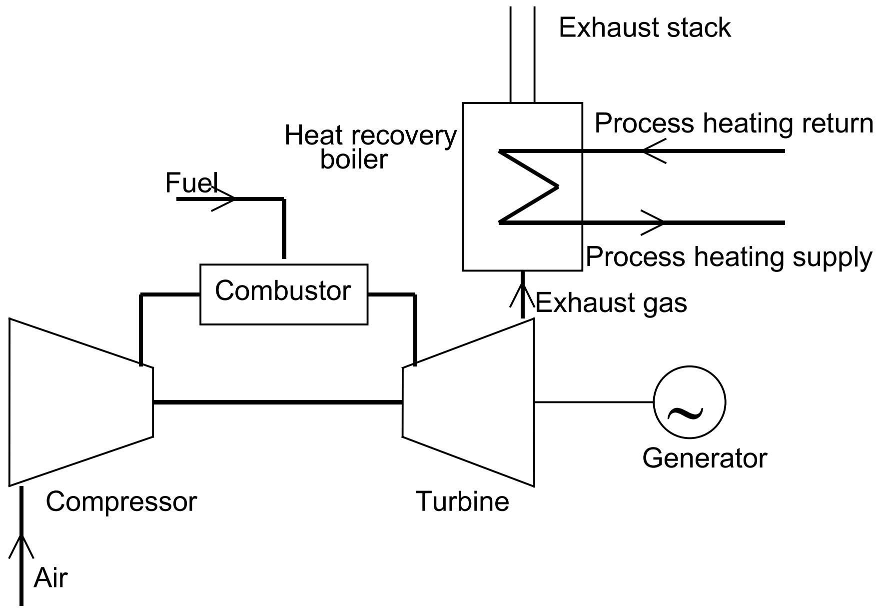
Description of Technology

Combustion turbines, often called gas turbines, generate electricity and heat by combusting fuel in a combustion chamber and using the hot gas to rotate a turbine and generator. Combustion turbines can utilize different fuels such a natural gas or diesel fuel. The combustion cycle is described as follows:

- The conventional gas turbine is an open process, with the intake air and exhaust gas respectively being taken from and released to the surroundings at atmospheric pressure.
- Air is compressed in a compressor, thereby increasing both the pressure and temperature.
- The compressed air is delivered to a combustion chamber where it is mixed with gaseous or liquid fuel and burned. The combustion takes place at a constant pressure and occurs with large quantities of excess air. The turbine exhaust contains oxygen (about 15% O_2) and is therefore capable of supporting additional combustion.
- The high-temperature, high-pressure gaseous combustion products enter the turbine, where the expanding gases perform mechanical work by rotating the turbine shaft. A portion of the produced work is used to drive the compressor and overcome friction, and the remainder is available for power production.
- In cogeneration applications the heat in the hot exhaust gas is recovered in a heat recovery steam generator (HRSG) or directly used in an industrial process.
- The heat in the exhaust gas can be augmented with supplemental firing of additional fuel ahead of the HRSG. The fuel is converted to usable thermal energy at an efficiency exceeding 90 percent.

[3] "Integrating District Cooling with Combined Heat and Power," Resource Efficiency, Inc. for the International Energy Agency, ISBN 90-72130-87-1, 1996.

Figure B.1
Schematic for gas turbine cogeneration



Gas turbines are commercially available in a range of sizes, from 500 kW to over 300 MW. In addition, a new generation of small systems generally called "microturbines" are being developed in sizes down to 30 kW.

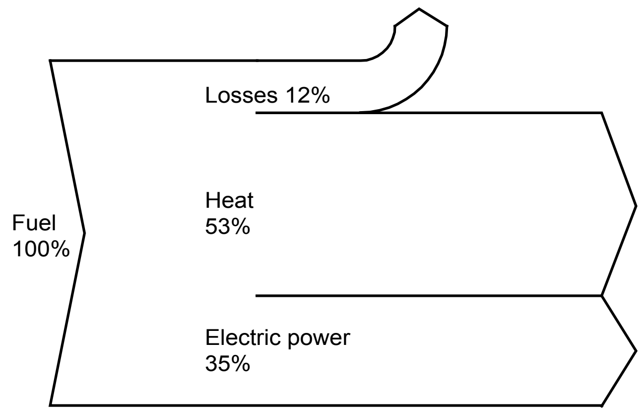
Natural gas and light to heavy fuel oil can be used as fuel for combustion turbines. While natural gas is a "clean" fuel and is relatively problem-free to use in a gas turbine, heavier fuel oils must usually be cleaned to reduce the level of substances that can cause high temperature corrosion or surface deposits in the hot gas path of the turbine. One potentially problematic aspect of using natural gas is the pressure level of the natural gas. With the high pressure ratio (pressure in the combustor after the compressor, divided by intake air pressure) of modern gas turbines, the pressure of the natural gas from low pressure pipelines must be boosted by the use of a separate gas compressor to be able to use the gas in the gas turbine. This adds additional capital and operating costs to the project, increases the amount of parasitic electrical load to drive the compressor and reduces the amount of net electrical energy available for the end user.

Research and development for gas turbines is intensive due to the large and expanding market. R&D efforts are primarily focused on increasing efficiency and/or reducing emissions (primarily NO_X). All major manufacturers of gas turbines 20 MW and larger now have combustors available or on the drawing board for NO_X emissions below 0.1 lb/MMBTU for natural gas without external cleaning or steam/water injection. Increased turbine inlet temperature is the main alternative for increasing the efficiency. R&D is therefore focused on advanced cooling of turbine blades and materials that can sustain turbine inlet temperatures of 2200 to 2550°F (1200 to 1400°C). Electric efficiencies above 40% are now attained by commercial aeroderivative gas turbines, with the latest industrial gas turbines having typical efficiencies of 35-38%.

Performance

Figure B.2 summarizes the electric and thermal efficiency of a representative gas turbine under ISO conditions.

Figure B.2
Sankey diagram (LHV) for cogeneration with gas turbine (size range 20 MW)



Electric efficiency is generally higher in the larger turbines, ranging from 25% for very small turbines (1-2 MW) to 35-40% for larger turbines (20 MW and up). Efficiencies in the 20-40 MW interval are relatively high because many aeroderivative gas turbines, which generally have higher efficiencies, are available in that size range.

The temperature effect of intake air on the *power output* of a combustion turbine is significant. Although there are variations between units, for most turbines, power output increases by about 10% for every 59°F (15°C) drop in outdoor temperature, and conversely output decreases by about 10% for every 59°F (15°C) increase in outdoor temperature.

In an economic evaluation of a cogeneration plant it is important to consider performance at different ambient temperatures depending on the climate conditions during which electric power is most valuable. Power output can be boosted by chilling inlet air to the compressor, either cooling directly on a baseload basis or indirectly through a thermal storage system.

The electric conversion efficiency of gas turbines can be increased by increasing the turbine inlet temperature and/or by increasing the pressure ratio. The compressor section heats the air and raises the pressure to the turbine. By adding or removing stages to the compressor the turbine inlet temperature and pressure ratio can be changed. Generally, a higher pressure ratio results in a lower exhaust temperature. However, lower exhaust temperatures also reduce the potential for thermal recovery, thereby decreasing total energy efficiency. Higher electric conversion efficiencies in gas turbine combined cycles can be obtained for turbines which have higher exhaust temperatures in simple cycle mode.

Emissions

Emissions can vary based on the particular gas turbine equipment, fuels used, and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility specific factors.

The main environmental concern regarding gas turbines is the nitrogen oxides (NO_X) emission. Gas turbine plants can reach NO_X emissions below 0.1 lb/MMBTU without any external flue gas cleaning. Low NO_X emissions were previously achieved by injecting steam or water into the combustion chamber, which decreases the efficiency and increases the operating cost. Most manufacturers of medium to large size (> 5 MW) gas turbines can now meet emission limits with dry low-NO_X combustors. Dry low-NO_X combustors typically utilize a staged lean-burn combustion process to reduce the temperature of combustion and resulting in less production of nitrogen oxide emissions.

Carbon dioxide emissions, also a concern for fuel combustion facilities, are related directly to the amount of fuel burned. Natural gas combustion results in CO_2 emissions of about 0.11 lb/MMBTU of gas burned, although this can vary somewhat depending on the chemical properties of the natural gas.

Economics

Gas turbine capital, operating and maintenance (O&M) costs are extremely sensitive to size. A comparison of capital costs and O & M costs is presented in the following table. Capital costs range from up to $1600/kW for a 1 MW combustion turbine cogeneration system to less than $700/kW for large systems (over 100 MW).

Table B.1
Summary of Generalized Capital and Operating Costs of Gas Turbine Cogeneration [4] [5] [6] [7] [8]

Size (MW)	Capital Cost ($/kw)	O&M Cost ($/kWh)
1-2	1200-1600	0.008-0.010
5-25	800-1050	0.005-0.006
25-100	650-780	.004-.005
>100	<650	<.003

[4] "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector," OnSite Sycom Energy Corp. for the U.S. Department of Energy, January 2000 (Revision 1).
[5] Gas Turbine World 1999-2000 Handbook, Gas Turbine World magazine, Vol. 20.
[6] "Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications," Lund University Press, 1989.
[7] "Existing District Heating System Based Economical Power Production," Parson Brinckerhoff Energy Systems Group, International District Energy Association Annual Conference, 1994.
[8] "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

Gas turbine operation and maintenance (O&M) costs include: 1) monthly maintenance that can be accomplished without equipment shutdown; 2) periodic maintenance (approximately every 4,000 hours of operation) including borescope inspection for blade erosion and checkout of fuel systems, sensors and controls, burner cleaning; and 3) major overhaul at intervals of 30,000 to 40,000 hours.

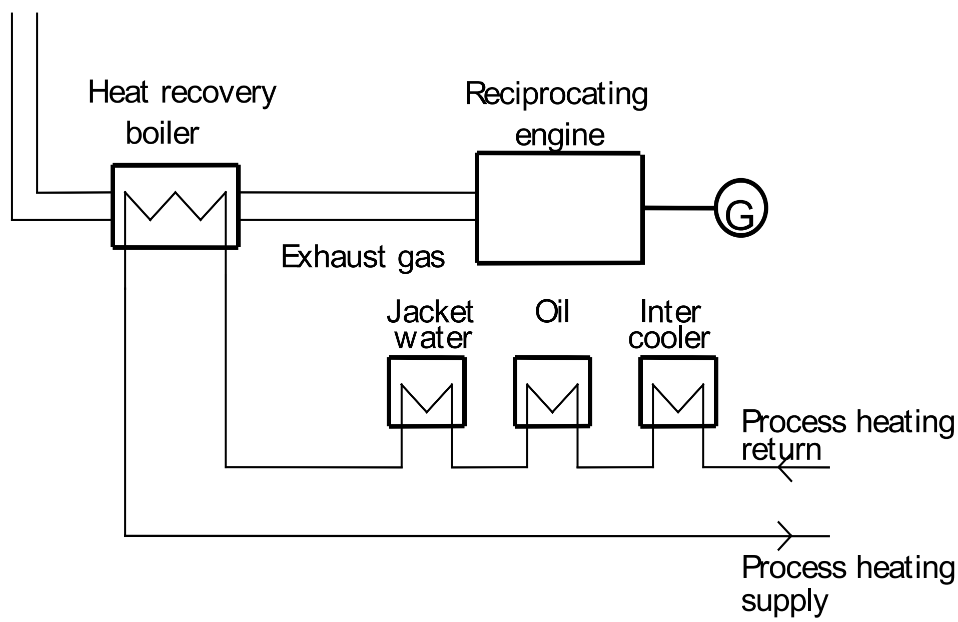
B.3 Reciprocating Engines

Description of Technology

Reciprocating engine cogeneration is illustrated in Figure B.3 and can be briefly described as follows:

- Fuel and air enter a combustion chamber where it is ignited either by compression (diesel cycle) or a spark (Otto cycle) and drives a piston attached to a crank shaft.
- A generator attached to the engine shaft generates electricity.
- Heat is recovered when the hot exhaust gas is cooled in a heat recovery boiler.
- Heat can also be recovered from the engine cooling water and oil lubrication system.
- In addition, heat can be recovered from the turbocharger and intercooler.

Figure B.3
Schematic for reciprocating engine cogeneration



The diesel engine is dominant over Otto engines in sizes above 1-2 MW. Both the diesel engine and the Otto engine can be found in a number of different applications and designs, including 4 and 2 stroke, with 1 to 20 cylinders. Turbochargers are common on both Otto engines and diesel engines to increase the efficiency and power output. Diesel engines are available in sizes up to 50 MW. Otto engines are usually limited to below 2 MW, although some manufacturers are developing larger (5-10 MW) Otto engines because it is increasingly difficult to meet nitrogen oxide emission limits with diesel engines without expensive catalytic converters. These engines are sometimes called "spark-ignited diesel engines" or "gas engines."

Multiple-stage intercoolers that cool the compressed combustion air before it enters the combustion chamber as well as exhaust gas turbines producing additional electricity can be used for larger engines if economical. A multi-stage intercooler allows some of the heat rejected from the cooling of compressed air to be available at a higher and more usable temperature. An exhaust gas turbine converts some of the high temperature "waste" heat to electricity. Many variations are possible for the design of specific equipment for cogeneration, depending on site-specific conditions.

Both gaseous and liquid fuels can be used in reciprocating engines. However, fuel ignition in diesel engines presents a challenge when using natural gas (with an ignition temperature of about 1200°F (650°C) as opposed to about 480°F (250°C) for fuel oil). Conversion of reciprocating engines to use gaseous fuels is achieved in two ways:

- *Injection of oil as a "pilot fuel," using about 5% oil at full load and up to about 10% at part loads.* This can be achieved by mixing air with gas fuel outside the engine. However, in modern larger diesel engines converted to gas combustion the gas fuel is compressed in an external compressor up to a pressure of about 3650 psig (250 bar). The compressed gas is then injected into the engine, where air already has been compressed, just before the ignition point. With this method, the power output is usually not affected by conversion to gaseous fuels, and the engine can be switched between gaseous and liquid fuels.

- *Conversion to spark ignition (Otto engine) in combination with "lean burn" (high air/fuel ratio) designs.* This is generally the approach taken with smaller (under 6 MW) engines, although R&D is continuing to increase the size of engines employing this approach due to its environmental benefits. One disadvantage is the lack of ability to switch fuels. This modified engine has a higher compression ratio than a normal Otto engine but low enough not to self-ignite. The electric efficiency of this modified engine is higher than a conventional Otto engine.

Since the beginning of 1970s, intensive diesel engine R&D has been performed, especially regarding diesel engines for ships due to rapidly increasing oil prices during that time. During the 1970s and 1980s the efficiency was increased from 40% to over 50% for the most efficient two-stroke engines. Substantial increases in efficiency are not expected in the near future. Instead, R&D is concentrated on reducing emissions and maintenance requirements and, to a lesser extent, use of alternative fuels.

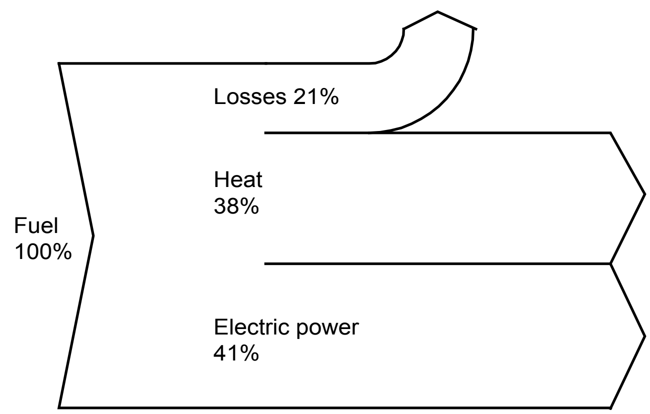
Performance

<u>Electric and Thermal Efficiency:</u>

Electric conversion efficiencies for diesel engines are usually in the range of 40-45% (Figure B.4). Efficiencies over 50% can be achieved with slow-speed two-stroke engines. However, these engines are larger in size (about 15 MW and above), are expensive and have higher emissions relative to gas turbines, with which they will be competing in this size range. The higher efficiency slow-speed two-stroke engines are not addressed in this report because gas turbines (simple cycle or combined cycle) are usually a better choice from the standpoints of both economy and emissions.

For a diesel cogeneration plant the ratio of electric output to thermal output will be slightly above 1.0, and the total efficiency will be about 80%, assuming recovery of thermal energy for a process heating hot water system with 212/167°F(100/75°C) supply/return temperatures.

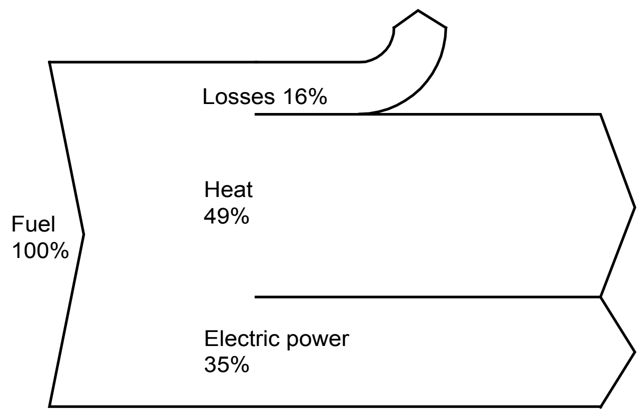
Figure B.4
Sankey diagram (LHV) for cogeneration with diesel engine
(4 stroke, size range 5-15 MW)



The electric efficiency is unchanged regardless of heat supply temperature as long as the intercooler or jacket water temperatures are not raised to accommodate higher heat supply temperatures. Heat recovery up to 212°F (100°C) heat supply temperature is based on hot water with a 77°F (25°C) temperature increase from the engine. Above 248°F (120°C), saturated steam with a condensate return temperature of 100°C is assumed. The total efficiency decreases with increasing heat supply temperatures. However, it is important to note that if there is a use for lower temperature hot water, an additional hot water heat recovery boiler can be installed to raise the total efficiency up to the same level as for hot water heat recovery only.

For Otto engines the electric conversion efficiency ranges from 30-40%, with 35% as a representative value for engines up to 2 MW, as shown in Figure B.5. A total efficiency of around 85%, with an electric/thermal output ratio in the range of 0.55-0.90, can be reached for a cogeneration Otto engine assuming 100/75°C thermal energy recovery. For larger Otto engines or lean-burn gas engines the performance is similar to the performance for a diesel engine. While the gross electric efficiency can be higher for the diesel engine, this can be offset by the electric consumption for compressing gas to the required high pressure in situations where a low pressure gas pipeline supplies the fuel.

Figure B.5
Sankey diagram (LHV) for cogeneration with Otto engine
(size range 1-2 MW)



Emissions

Emissions can vary based on the particular engine, fuels used and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility-specific factors.

NO_X emissions from reciprocating engines are relatively high compared to other energy conversion equipment. For a diesel engine the NO_X emissions are around 2-3 lb/MMBTU fuel input without cleaning equipment. Selective catalytic reduction (SCR) is usually used, with a possible emission reduction around 90-95 percent. SCR is normally not used for Otto engines. Instead, two other methods can be used: 1) three-way catalytic converters (non-selective catalytic reduction); and 2) lean-burn which provide reductions comparable to SCR systems.

Economics

<u>Capital Costs</u>
Capital costs for cogeneration plants based on reciprocating engines are generally in the range of \$1000 - \$1400/kW for small units to \$800 - \$900/kW for large units.[2] These values represent the total investment for equipment and installation.

<u>Operation and Maintenance Cost</u>
The operation and maintenance cost for reciprocating engines includes oil consumption, oil changes, replacement of components such as filters, gaskets and spark plugs, and major overhauls at an interval of approximately 50,000 hours. For small Otto engines, below 1 MW, the operation and maintenance cost is in the range of 1.0-2.0 cents/kWh, and for larger Otto and diesel engines 0.5-1.0 cent/kWh. With SCR, 0.25-0.5 cent/kWh should be added.[2 9 10]

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[9] Manufacturers data from Wartsila and Caterpillar.

B.4 Steam Turbines

Description of Technology

A steam turbine uses steam to generate electricity. The basic elements of steam turbine cogeneration are illustrated in Figure B.6, and can be briefly described as follows:

- Fuel and air are combusted in a boiler, generating steam. To increase the efficiency of the steam turbine cycle the steam is normally superheated.
- The steam exits the boiler and is directed to the steam turbine, where the steam expands through the turbine, turning the turbine blades that are connected to the electric generator shaft.
- In a backpressure turbine, the steam is exhausted above atmospheric pressure to a heat exchanger where thermal energy is transferred at a relatively low pressure to the thermal loop or steam-driven chiller.
- If higher pressure steam is required, some steam is extracted through ports in the turbine prior to exhaust or the exhaust pressure is increased.
- In a condensing turbine, the steam is condensed using a cooling tower, ground water or surface water, exiting at less than atmospheric pressure. Since turbine efficiency is directly related to the difference between inlet and exhaust steam pressures, condensing (non-cogeneration) turbine plants provide the highest electric efficiency.
- As illustrated in Figure B.6, some cogeneration steam turbine plants include a condensing tail turbine (the low pressure turbine in the figure) to increase the electric output regardless of thermal demand.
- In some steam turbine plants a reheat cycle is used, in which steam is extracted from the turbine and reheated in the boiler during the expansion process. Reheat cycles, with one or two reheat points, improve the overall thermal efficiency because the average temperature of the heat supply is increased.
- Steam turbine plants usually also include a regenerative cycle in which steam is extracted from the turbine and used to preheat boiler feed water. This increases overall efficiency because the steam's latent heat of condensation is returned to the process, thereby increasing the average temperature of the heat supply.

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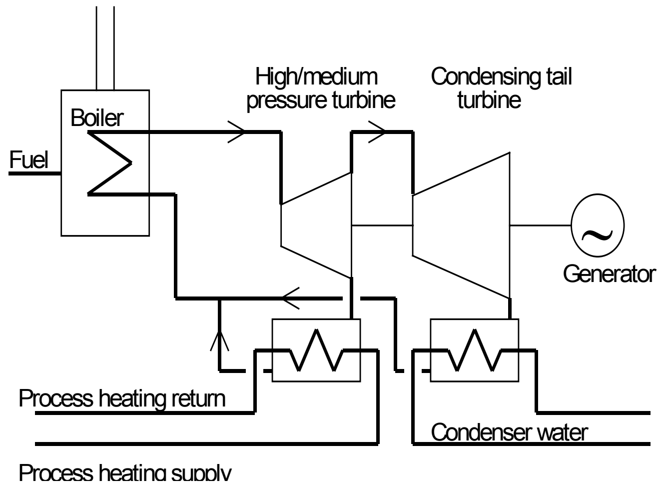
[10] "Small Scale Combined Heat and Power," Energy Technology Series #4, Energy Efficiency Office, United Kingdom.

Figure B.6
Schematic for cogeneration with steam turbine, including condensing tail turbine



Independent steam turbine power plants (i.e., steam turbines which are not just a component of a larger plant) are available in sizes ranging from 5 MW to over 1000 MW, and are the most common type of power plant in use worldwide. (As a component in a larger plant, steam turbines are available in sizes of under 1 MW.) One of the strengths of this technology is the ability to use a wide variety of fuels, including solid fuels and waste materials.

As is the case for all power generation equipment, the steam turbine cycle efficiency would benefit from raised temperature of the heat supplied to the process. While the temperature of the supplied heat to gas turbine cycle has increased rapidly during the last 10 years, the temperature to the steam turbine cycle has been stable at around 1000°F (540°C).

The main difference in the evolution of combustion turbines and steam turbines can be traced in part to the amount of material that must withstand the higher temperatures. For a gas turbine, only the combustor, inlet guide vanes and turbine blades must withstand the higher temperatures, thereby limiting the amount of expensive material needed. For a steam turbine cycle, a large part of the boiler surfaces must withstand the higher temperatures as well as the intake stages of the turbine.

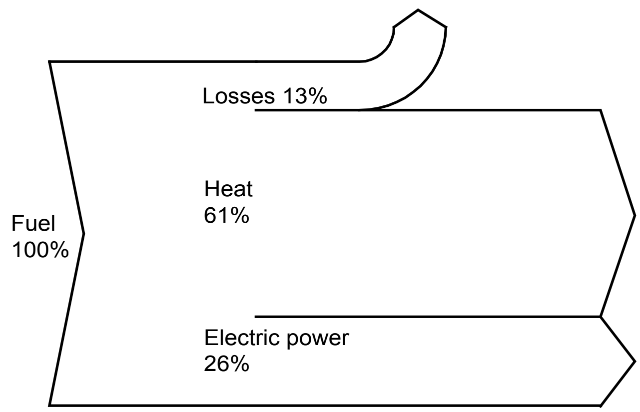
Technology and material for withstanding temperatures above 1000°F (540°C) steam temperatures (such as high-alloy ferritic/martensitic steel, austenitic steel and/or superalloy steels instead of low-alloy ferritic steels used up to 1000°F (540°C) steam temperature) are available but thus far the cost/benefit ratio has been too high. However, R&D for increasing the steam temperature above 1100°F (600°C) is ongoing, raising the possibility of increasing the condensing steam cycle plant efficiency to 45-46% (LHV).

Performance

Electric and Thermal Output

Figure B.7 shows a generalized Sankey diagram for steam turbine cogeneration in the 25 to 50 MW range based on 100/75°C heat extraction. For larger cogeneration plants employing reheat, higher steam pressures and additional feed water preheaters, the electric efficiency can be increased to above 30%.

Figure B.7
Sankey diagram (LHV) for typical steam turbine cogeneration
(size range 25-50 MW)



For a cogeneration plant with a process heating hot water temperature of 212/167°F (100/75°C), the electric efficiency is about 10% lower than a comparable condensing cycle without cogeneration. The part-load performance of steam turbines is in between those of reciprocating engines and gas turbines.

For a cogeneration plant the overall efficiency can be as high as 90% with an electric efficiency of slightly over 30%, compared with the overall efficiency of 40% for a condensing cycle without cogeneration The electricity lost due to heat extraction will generally be about 0.15 units of electricity per unit of heat at 212°F (100°C) extraction. The overall efficiency of a steam cogeneration plant is greatly affected by how low a stack temperature can be allowed relative to acid dew point and flue gas dispersion, and the extent to which excess air can be limited without increasing carbon monoxide (CO) and uncombusted carbon.

Electric usage for auxiliary fuel handling equipment is higher for solid fuel-fired plants than for oil- or gas-fired plants, but compared to the stack losses the electric usage for auxiliaries has a relatively small effect on the overall efficiency. Boiler efficiencies range from about 80% for a boiler with high excess air and high flue gas temperature to above 90% for a larger boiler with good air supply controls and an air preheater.

The electric efficiency for a steam turbine decreases with increasing heat supply temperature while the total efficiency is unchanged (as long as the return temperature of the thermal or condenser loop is constant). This contrasts with reciprocating engines and gas turbines, where the electric efficiency is unchanged for different heat supply temperatures while the total efficiency decreases with increased heat supply temperature.

Emissions

Emissions are related to the boiler technology, fuels used, and flue gas cleaning equipment, and can vary within a wide range. Actual emissions for a facility can only be determined based on facility-specific. Major emissions may consist of nitrogen oxides, sulfur dioxides, carbon monoxide, carbon dioxide and particulates It may be difficult to permit these type of facilities in areas designated as non-attainment areas for these emissions.

Economics

Capital Costs

Gas-fired plants range in cost from less than $1000/kW for large plants to nearly $2000/kW for a 5 MW plant. Solid-fuel-fired plants range in cost from $1500/kW for large plants (over 500 MW) to $2000-2400/kW for smaller plants (10-25 MW).[1] In cogeneration mode the electric output is reduced although the same size boiler and auxiliaries are employed.

Operation and Maintenance Costs

Operation and maintenance (O&M) costs vary between 1.25 cents per kWh for smaller steam turbines (25 MW) to 1.00 cents/kWh for larger steam turbines (100 MW). O&M costs are highly dependent on the type of fuel being burned in the boiler. Higher O&M costs are associated with solid fuel fired boilers versus liquid/gaseous fuel fired boilers. [1]
[11]

B.5 Combined Cycles

Gas Turbine Combined Cycle

Description of Technology

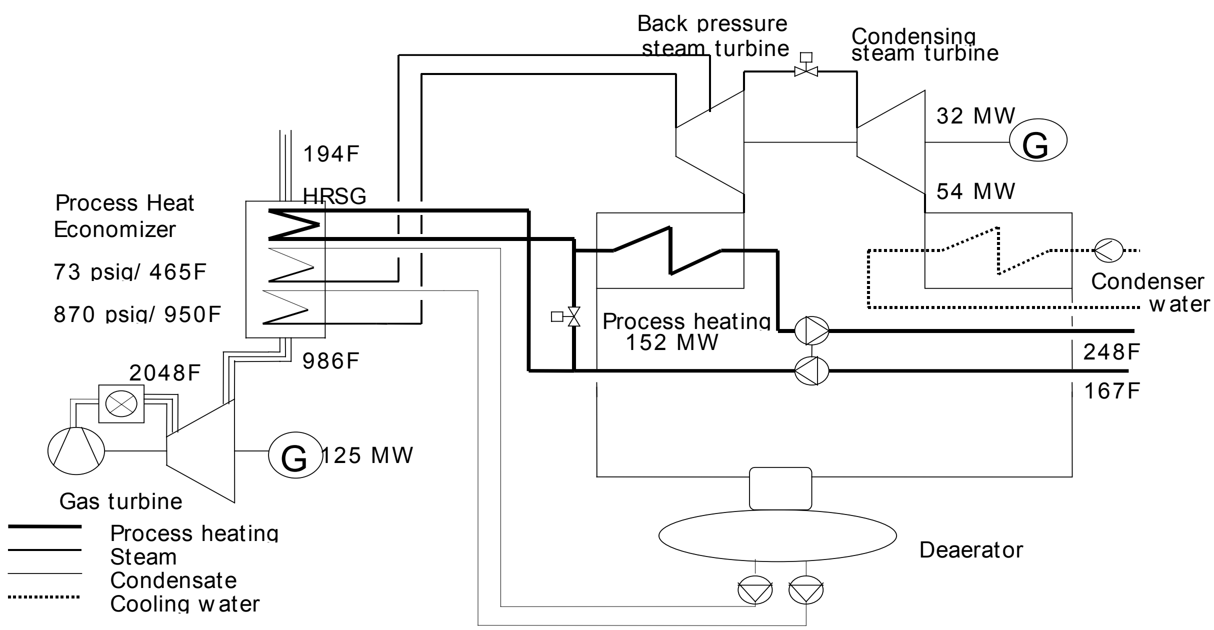
The gas turbine combined cycle is an increasingly common configuration. A combined cycle uses the waste heat from a combustion turbine to generate steam and drive a steam turbine. Figure B.8 illustrates an example of a combined cycle, showing components for both condensing and cogeneration options. Temperatures and pressures vary depending on the particular combined cycle configuration; this figure shows one example for illustrative purposes.

- Natural gas or liquid fuel is combusted in the gas turbine, producing electricity and hot flue gases as described previously in B.2.
- The hot flue gases enter the Heat Recovery Steam Generator (HRSG), where heat is recovered to produce steam (and, in some cogeneration operations, hot water). Output can be increased through supplemental firing, in which additional fuel is combusted using the high oxygen content in the exhaust gas. Supplementary firing can improve the overall efficiency and can improve electric efficiency at part-load conditions.

[11] "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

- Steam is used to produce additional electricity in a steam turbine (in the example shown, 32 MW in cogeneration mode and 54 MW in condensing mode).
- The steam cycle usually has 2-3 pressure levels; the higher steam pressure to enhance the electric efficiency and the lower pressure to enhance the heat recovery efficiency.
- To increase the overall efficiency a process heating economizer also can be installed in the HRSG.

Figure B.8
Example schematic of a gas-fired combined cycle cogeneration plant

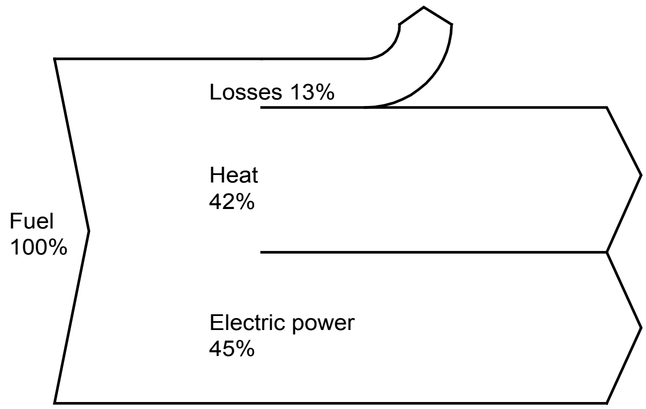


Performance

Electric and Thermal Output

Electric efficiency above 50% can now be reached with many gas turbine combined cycle in condensing mode, with some systems reporting an efficiency of 60%.[2] In cogeneration mode with an extraction temperature of 212/167°F (100/75°C), an electric efficiency of about 45% can be expected, with a total efficiency of about 87% as shown in Figure B.9.

Figure B.9
Sankey diagram (LHV) for gas turbine combined cycle cogeneration



Industrial types of gas turbines tend to have a somewhat lower simple cycle efficiency, but a longer service life, compared to aero-derivative gas turbines. Selection of an aero-derivative versus industrial grade turbine in normally based on the lowest overall life cycle cost. With a combined cycle with one pressure level, the electric efficiency in industrial-type gas turbines is 13-17% higher than the comparable simple cycle. Adding one to two pressure levels can boost electric efficiency by another 1-2%. The efficiency improvement achievable through a combined cycle is generally lower with aero-derivative gas turbines because these types of turbines tend to have a lower exhaust temperature.

The gas turbine combined cycle in condensing mode can reach an electric efficiency around 50%, with an efficiency above 55% possible in larger facilities with multiple steam pressure levels. The design of particular facility is based on performing a life – cycle cost analysis to determine the lowest overall system cost, taking into account first costs as well as operating costs.

Supplementary firing in the heat recovery boiler can be used to increase the overall efficiency. Supplementary firing will normally decrease the electric efficiency because the fuel is not utilized at the highest possible temperature, i.e. in the gas turbine. However, with low exhaust temperatures at part-load conditions, supplementary firing can increase the electric output.

Emissions

Emissions will vary based on the particular gas turbine equipment, fuels used and flue gas cleaning equipment. Actual emissions for a facility can only be determined based on facility-specific.

The emissions per unit of fuel input are comparable for a gas turbine simple cycle and a gas turbine combined cycle. However, the combined cycle will have lower emissions per unit of electricity due to the higher electric efficiency.

Economics

Capital and operating costs for condensing combined cycle plants have higher capital costs due to the costs associated with the steam turbine and associated generator.

Solid Fuel Combined Cycle

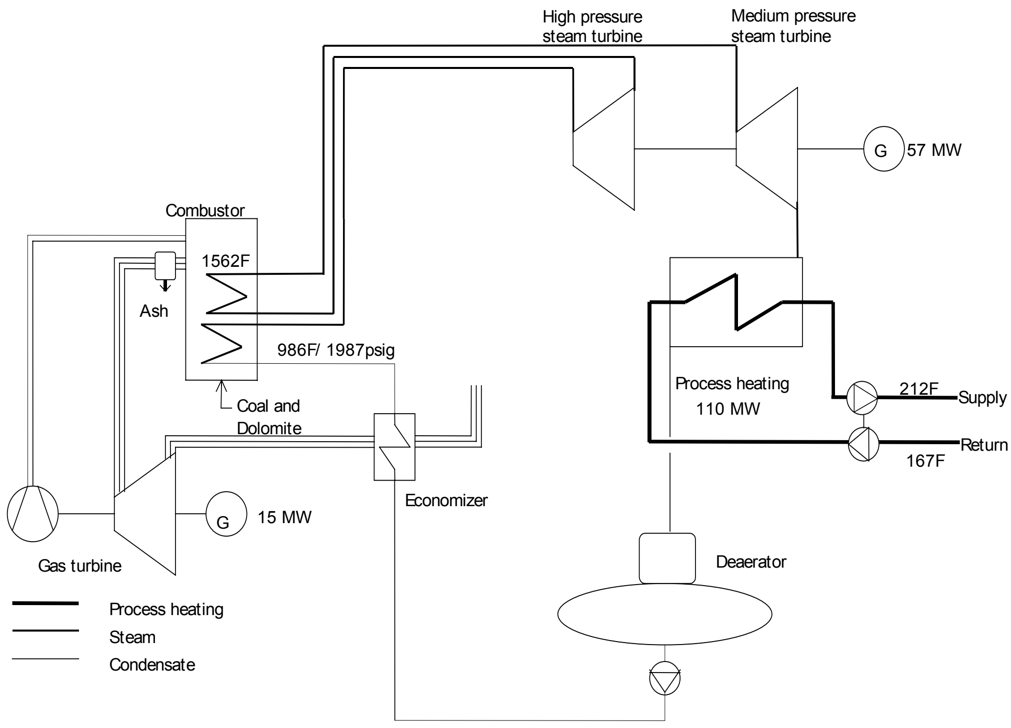
Description of Technology

Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC) technologies have been implemented to increase the efficiency of power production from solid fuels primarily consisting of coal or wood.

The basic layout of a PFBC is close to a natural gas combined cycle (see Figure B.10). The main difference is the combustor, which in a PFBC plant is substantially larger and is a fluidized bed boiler. The gas turbine provides compressed air to the boiler and, because of the pressurization of the boiler 175-232 psig (12-16 bar), the size can be considerably smaller compared to what would be required for a normal solid fuel boiler with the same (electric or thermal?) output.

Solid fuel, typically coal or wood waste, is injected into the combustor. Combustion takes place in a bed of limestone that is suspended in the combustion chamber utilizing large combustion air fans. The bed acts like a "fluid". Combustion takes place in the fluidized bed at a low temperature, 1560°F (850°C). The low combustion temperature reduces the formation of NO_X but is also essential to avoiding ash agglomeration. Steam is generated from water circulated through the fluidized bed to cool the bed and distributed to the steam turbine. Limestone or dolomite is injected into the bed to capture sulfur during combustion. Particulates from the hot flue gas are cleaned with cyclones before entering the gas turbine. In addition to supplying the boiler with compressed air, the gas turbine also provides about 20% of the electric output with the steam turbine producing about 80% of the electric output

Figure B.10
Schematic for a solid fuel-fired combined cycle cogeneration plant (PFBC)



PFBC plants are competing with coal gasification for high technical and environmental performance utilizing coal. Because of the limited market, the price for a PFBC plant under commercial conditions is uncertain. However, the technical and environmental performance should make PFBC an important future option for use of coal for cogeneration.

Performance

Electric and Thermal Output

A higher electric efficiency as well as improved emissions can be reached with a PFBC compared to conventional solid fuel power plants. An electric efficiency of 44-46% LHV can be reached in condensing mode. In cogeneration mode, electric efficiency can reach 34%, with an overall efficiency of 89% LHV. [12]

Emissions

The environmental performance from existing PFBC plants is almost equivalent to gas-fired plants. The absorption of sulfur in the bed can reduce the SO_2 emissions by over 95%. NO_x emissions around 0.02 lb/MMBTU have been obtained with ammonia injection and a small catalytic aid in the flue gas duct. Measured levels of CO and N_2O

[12] "Electric Power Technologies: Environmental Challenges and Opportunities," Report to the Committee on Energy Research and Technology, International Energy Agency, 1993.

are less than 200 parts per million by weight (ppm) and 10 ppm, respectively. With a textile baghouse, the particulate emissions are around 0.004 lb/MMBTU.

B.6 Fuel Cells

A number of new technologies are under development for advanced cogeneration, including supercritical steam cycles, various technologies for gasification of coal and/or biomass, and fuel cells. Of these, the fuel cell is perhaps of greatest interest due to its environmental advantages. For this reason, fuel cells will be briefly addressed here, although not in the depth of the cogeneration technologies presented earlier in this chapter.

Description of Technology

Fuel cells generate electricity and heat through an electrochemical conversion process similar to that long been applied in automobile batteries. Chemical energy is converted to electricity when hydrogen is combined with oxygen to make water. Hydrogen gas can be provided directly to the fuel cell. The hydrogen can be extracted from anything that contains hydrocarbons, including natural gas, biomass, landfill gas, methanol, ethanol, methane and coal-based gas. In the past, units are available in 200 kW modules that can be combined to provide larger installations, although larger units are now becoming available.

Different types of fuel cells are named according to the type of medium used to combine the hydrogen and oxygen. Three types of fuel cells are usually considered for cogeneration applications:

- Phosphorous acid cells, now operating in various sites providing cogeneration. Applications include schools, high rise office buildings and credit card processing centers.
- Molten carbonate systems, now in the demonstration phase for baseload power.
- Solid oxide cells, with a small-scale unit now in the demonstration phase.

Several other types of fuel cells are in use or being developed for various other applications:

- Alkaline -- used in space applications since the 1960s.
- Proton exchange membrane -- for transportation and small-power applications.

Performance

Fuel cells are highly efficient because they convert chemical energy directly into electricity without going through an intermediate combustion step. Total efficiencies exceeding 80% can be achieved when both heat and electricity are used. Efficiency is maintained over a wide range of unit operation.

Emissions

Virtually no emissions are produced in this process (zero emissions if pure hydrogen is used).

Economics

Currently, fuel cell cogeneration systems have a capital cost of approximately $3,000/kW.

Appendix C
Fuel Conversion Factors

Fuel	MMBtu/unit
Natural Gas	1028.00/mmcf
Fuel oil	138.69/1000 gallon
Residual (#5,6)	149.69/1000 gallon
Propane	91.33/1000 gallon
Gasoline	125.07/1000 gallon
Jet fuel	135.00/1000 gallon
Coal - Industrial	20.69/ton
Coal - Utility	17.45/ton
Wood - Industrial	12.80/ton
Ethanol	84.40/1000 gallon
Anthracite	25.00//ton
Bituminous	22.00/ton
Distillate (#1-3)	138.69/1000 gallon
Pet Coke	30.12/ton

Appendix D – References

1. "Integrating District Cooling with Combined Heat and Power," Resource Efficiency, Inc. for the International Energy Agency, ISBN 90-72130-87-1, 1996.

2. "The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector," OnSite Sycom Energy Corp. for the U.S. Department of Energy, January 2000 (Revision 1).

3. Gas Turbine World 1999-2000 Handbook, Gas Turbine World magazine, Vol. 20.

4. "Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications," Lund University Press, 1989.

5. "Existing District Heating System Based Economical Power Production," Parson Brinckerhoff Energy Systems Group, International District Energy Association Annual Conference, 1994.

6. "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

7. Manufacturers data from Wartsila and Caterpillar.

8. "Small Scale Combined Heat and Power," Energy Technology Series #4, Energy Efficiency Office, United Kingdom.

9. "Technical Assessment Guide, TRI02276," Electric Power Research Institute, Sept. 1993.

10. "Electric Power Technologies: Environmental Challenges and Opportunities," Report to the Committee on Energy Research and Technology, International Energy Agency, 1993.

11. "Opportunities to Expand Cogeneration in Minnesota," Center for Energy and Environment.

12. Per 1990 emissions data provided to the Minnesota Pollution Control Agency.

13 "The Market and Technical Potential for Combined Heat and power in the Commercial/Institutional Sector" Revision 1, Jan. 2000.

Appendix E – Survey Recipients Ranked by Total Fuel Use

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
7100002	Boise Cascade Corp - International Falls	7,871,515	Brent	Walchuk	2182855522	International Falls	MN	56649
7500003	Northshore Mining Co - Silver Bay	7,646,420	Nancy	Smith	2182266083	Silver Bay	MN	55614
1700002	Potlatch - Cloquet	5,972,705	Kevin	Kangas	2188790638	Cloquet	MN	55720
6100001	Blandin Paper Co	5,957,718	Curt	Firman	2183276306	Grand Rapids	MN	55744
11900002	American Crystal Sugar - E Grand Forks	5,421,375	Annette	Cederberg	2182364304	Moorhead	MN	56560
5700005	Potlatch - Bemidji (MN Wood Products)	5,297,152	Steve	Bailey	2187511708	Bemidji	MN	56601
12900014	Southern Minnesota Beet Sugar COOP	4,655,669	Glenn	Augustine	3203294149	Renville	MN	56284
8300038	Minnesota Corn Processors	2,920,295	Michael	Rutledge	5075372676	Marshall	MN	56258
2700001	American Crystal Sugar - Moorhead	2,905,179	Annette	Cederberg	2182364304	Moorhead	MN	56560
11900001	American Crystal Sugar - Crookston	2,828,745	Annette	Cederberg	2182364304	Moorhead	MN	56560
900011	Champion International Corp - Sartell	2,679,806	Keith	Sowada	3202407340	Sartell	MN	56377
5300011	NRG Energy - Mpls Energy Ctr (Main)	2,011,678	Henry	Hanson	6123496087	Minneapolis	MN	55404
1700006	USG Interiors - Cloquet	1,824,137	Stephen	Povroznik	2188792800	Cloquet	MN	55720-1592
1300006	ADM - Mankato	1,676,848	Chris	Janick	2184244810	Decatur	IL	62525
12300694	3M - Maplewood - Administrative Offices	1,595,266	Linda	Tanner	6127785213	St Paul	MN	55133-3331
3500002	Potlatch - Brainerd (NW Paper Division)	1,519,452	Julie	Hendricks	2188286522	Brainerd	MN	56401-2198
13700005	US Steel Minn Ore Operations - Minntac	1,458,259	Stephani	Campbell	2187497468	Mountain Iron	MN	55768-0417
13700113	EVTAC Mining - Plant	1,404,181	Bradley	Anderson	2187447849	Eveleth	MN	55734
1300007	Cenex Harvest States Coop - Mankato	1,375,240	Jeff	Bergeland	5073452213	Mankato	MN	56002-3247
16300023	3M - Cottage Grove Specialty Matls-Film	1,292,993						
700019	Northwood Panelboard	1,253,301	John	Oschwald	2187512023	Solway	MN	56678-9731
13900013	CertainTeed Corp	1,147,033	Gary	Swenson	6124456450	Shakopee	MN	55379
13900003	Rahr Malting - Shakopee	1,055,021	Paul	Kramer	6124967002	Shakopee	MN	55379
8500049	3M - Hutchinson Tape Manufacturing Plant	1,048,516	Mike	Ossanna	6127784036	St Paul	MN	55133-3331
12300063	District Energy St Paul Inc-Hans O Nyman	1,015,315	Michael	Burns	6512978955	St Paul	MN	55102-1611
13700022	Duluth Steam COOP Assn	991,594	Gerald	Pelofske	2187233601	Duluth	MN	55802
12300055	North Star Steel MN	987,827	Judd	Ebersviller	6517315697	St Paul	MN	55164

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
6100010	Potlatch - Grand Rapids	976,570	Bruce	Trebnick	2183273650	Grand Rapids	MN	55744
13700083	Potlatch - Cook	971,683	Todd	Smrekar	2186666902	Cook	MN	55723
5700006	Lamb Weston - RDO Frozen Foods	884,752	Brian	Flynn	2187327252	Park Rapids	MN	56470
3500031	Trus Joist MacMillan - Deerwood	848,578						
15100026	CVEC - Benson Ethanol Plant	740,273	Jon	Buyck	3208434813	Benson	MN	56215
4300041	Corn Plus	712,861	Sheila	Helland	5078934747	Winnebago	MN	56098
1900001	Bongards' Creameries	654,366	Tom	Otto	6124665521	Norwood	MN	55368-9743
12300016	3M - St Paul Tape Manufacturing Division	645,268	Ade	Babatunde	6517787674	St Paul	MN	55133-3331
3300025	Ethanol 2000 LLP	629,674	Terry	Kulesa	5078310063	Bingham Lake	MN	56118
300073	Minnesota Correctional - Lino Lakes	626,459	Jim	Aleckson	6127806100	Lino Lakes	MN	55014
3700066	Spectro Alloys Corp	621,633						
12300039	Ford Motor Co - Twin Cities Assembly Plt	611,107	Marc	Daniels	6516960584	St Paul	MN	55116-1888
13100022	Malt-O-Meal Co - Plant 2 - Northfield	595,229	Robert	Johnston	5076456681	Northfield	MN	55057
13700031	Georgia-Pacific - Duluth Hardboard	592,044	Thomas	Lochner	2187208248	Duluth	MN	55802
1500010	New Ulm Public Utilities Commission	586,314	Gary	Dolmeier	5073598264	New Ulm	MN	56073
3900028	Al-Corn Clean Fuel	576,712	Randall	Doyal	5075282494	Claremont	MN	55924
4900007	USG Interiors - Red Wing	572,388	James	Wilson	6123883513	Red Wing	MN	55066
14300014	Heartland Corn Products	550,801	Ben	Brown	5076475000	Winthrop	MN	55396
9900002	Hormel Foods Corp - Austin	540,813	Lee	Johnson	5074375221	Austin	MN	55912
12900036	Minnesota Energy	538,983	Eileen	Koeberl	3208335939	Buffalo Lake	MN	55314
10500001	Swift & Company	536,625	Chuck	Tennessen	5073722121	Worthington	MN	56187
7300002	Ag Processing - Dawson	536,159	Lee	Gunderson	3207694386	Dawson	MN	56232
5300002	Hennepin County Energy Center	526,428	Patrick	Rainville	6123368531	Minneapolis	MN	55415
14500003	Kraft Foods Inc - Melrose	524,097	Larry	O'Donnell	3202567461	Melrose	MN	56352
14900013	Diversified Energy Co LLC	519,374	Gerald	Bachmeier	3205892931	Morris	MN	56267
10900006	IBM - Rochester	507,241	Cory	Landgren	5072532472	Rochester	MN	55901
2700022	Busch Agricultural Resources - Moorhead	454,231	Gregory	Ballentine	2182338531	Moorhead	MN	56560
10900008	St Mary's Hospital	452,035	Thomas	McNallan	5072556814	Rochester	MN	55902-1970
16900013	Froedtert Malt - Winona	410,498	David	Brunette	4146490284	Milwaukee	WI	53201
5300010	Northwest Airlines Inc\Mpls\St Paul Airp	408,878	Marvin	Dietrich	6127274842	St Paul	MN	55111-3034

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
7500019	Louisiana-Pacific Corp - Two Harbors	359,272	Barbara	Hamilton	2188345652	Two Harbors	MN	55616
12300022	University of St Thomas	321,739	Robert	Jacobs Jr	6129626530	St Paul	MN	55105
4900001	ADM - Red Wing	312,127	Chris	Janick	2174244810	Decatur	IL	62525
7300016	Associated Milk Producers Inc - Dawson	305,052	Joe	Vaske	6127692994	Dawson	MN	56232
5700002	Potlatch - Lumbermill - Bemidji	302,656	Peter	Aube	2187516144	Bemidji	MN	56601
14	Metropolitan Medical Center	300,000	Dwayn	Tapani	6123474531	Redwood Falls	MN	56283
15300006	Central Bi-Products - Long Prairie	294,338	Don	McCallum	5076372938			
12300053	MCES Metropolitan WWTP - St Paul	294,254	Keith	Buttleman	6516021015	St Paul	MN	55101
12700013	Central Bi-Products - North Redwood	289,830	Don	McCallum	5076372938	Redwood Falls	MN	56283
300020	Armament Systems Division United Defense	289,485	Douglas	Hildre	6125726938	Minneapolis	MN	55421-1498
6700054	Ridgewater College	278,146	Thomas	Wilts	3202315133	Willmar	MN	56201
16300003	Marathon Ashland Petroleum - St Paul Pk	258,164	Mike	Lukes	6514582726	St Paul Park	MN	55071
16100013	Brown Printing Co - Waseca Division	253,053	J	Schumacher Jr	5078350314	Waseca	MN	56093
5300790	NRG Energy - Mpls Energy Ctr (Riverside)	251,474	Henry	Hanson	6123496087	Minneapolis	MN	55404
3700016	Gopher Resource Corp	250,737						
5300813	Guest Credit Center	239,775	Keith	Kostial	6123045993	Minneapolis	MN	55416
14500008	St Johns University Order of St Benedict	229,569	Dan	Weber	3203632541	Collegeville	MN	56321
13700009	LTV Steel Mining - Hoyt Lakes	228,719	James	Stanhope	2182254373	Hoyt Lakes	MN	55750
13700039	University of MN - Duluth Upper	227,405	Craig	Moody	6126264399	Minneapolis	MN	55455
300019	Onan	226,149	David	Jacobsen	6125745000	Fridley	MN	55432
5300061	Abbott Northwestern Hospital	225,196	Bob	Hallman	6128634161	Minneapolis	MN	55407
13900009	Richards Asphalt Co	213,771	Byron	Richards	6128948000	Savage	MN	55378
1700003	Diamond Brands	212,173	Patrick	Wippler	2188782744	Cloquet	MN	55720-9990
10900010	Associated Milk Producers Inc -Rochester	212,077	Greg	McCutcheon	5072827401	Rochester	MN	55904
3700070	Van Hoven Co Inc	207,761	Melanie	Mornard	6514516858	South St Paul	MN	55075
14500026	St Cloud State University	204,054	Chuck	Lindgren	6122553166	St Cloud	MN	56301
4500049	Pro-Corn LLC	200,968	Richard	Eichstadt	5077654548	Preston	MN	55965
10900032	Quest International	187,986	George	Mathey	5072853400	Rochester	MN	55901
13700073	ME International - Duluth	187,592				Duluth	MN	
16300001	Andersen - Main	185,202	Kirk	Hogberg	6124307437	Bayport	MN	55003

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
12300036	Globe Bldg Materials	184,652	Oliver	Du Frene	6127762793	St Paul	MN	55106
12	Mankato State University	184,400	Robert	Isdahl	5073892222	Mankato	MN	
2700008	Moorhead State University	183,679	Alan	Breuer	2182362998	Moorhead	MN	56563
13300023	Agri-Energy LLC	183,587	Gordon	Heber	5072839297	Luverne	MN	56156
300155	Hoffman Enclosures Inc	182,448	Alan	Olson	6124222583	Anoka	MN	55303
4900062	Dairy Farmers of American Inc - Zumbrota	179,715	Steve	Ejnik	5077325124	Zumbrota	MN	55992
13100059	Minn Correctional Facility - Faribault	177,494	Richard	Schaefer	5073324506	Faribault	MN	55021
14500001	Kraft Food Ingredients - Albany	176,099	Daniel	Schneider	6128452131	Albany	MN	56307
14500032	Associated Milk Producers - Paynesville	173,183	Matt	Quade	3202433794	Paynesville	MN	56362
7900019	Unimin Minnesota Corp - Le Sueur	171,111				Le Sueur	MN	
13100007	Crown Cork & Seal - Faribault	170,847				Faribault	MN	
5300146	Honeywell - Golden Valley Home & Bldg	166,283	Greg	Weisjahn	6129544732	Golden Valley	MN	55422
14500067	Cold Spring Granite - Main Plant	160,360	Brian	Sjaaheim	6126853621	Cold Spring	MN	56368
13700166	St Mary's Medical Center	159,303	John	Rice	2187264693	Duluth	MN	55804
7900017	Le Sueur Incorporated	158,610						
9	Fairbault State Hospital	156,700	Brian	Youngberg	5073323304	Faribault	MN	
16300002	3M - Cottage Grove Indust Specialty	149,634						
10900036	Seneca Foods Corp - Rochester	149,557	Brian	Thiel	5072804531	Rochester	MN	55904
13100006	St Olaf College	147,869	Perry	Kruse	5076463280	Northfield	MN	55057-1098
13500002	Marvin Windows & Doors	146,152	Bradley	Baumann	2183861430	Warroad	MN	56763-0100
16300017	3M - Cottage Grove Abrasive Systems Div	143,739						
300156	Federal Cartridge Co - Anoka	142,997	Luke	Davich	6123232569	Anoka	MN	55303
700004	Georgia Pacific - Bemidji Hardboard	142,127	Gary	Wilson	2187515140	Bemidji	MN	56601
5300127	Owens-Corning - Mpls Plant	141,229	Joe	Orvik	6125223395	Minneapolis	MN	55430
1500007	OCHS Brick Co	137,462						
20	Stillwater State Prison	137,200	Bill	Mordick	6517792700			
3500008	State of Minnesota Dept of Human Service	137,006	Bernard	Baloun	2188282459	Brainerd	MN	56401
13100018	Carleton College	136,569	Kirk	Campbell	5076464133	Northfield	MN	55057
7100015	Intl Bildrite	135,759						

PCA ID#	facility	MM Btu/year	firstname	lastname	phone	city_b	state	zip_b
10	Fergus Falls Reg. Treatment Center	135,700	Les	Baird	2187397300	Fergus Falls	MN	
15700024	Lakeside Foods Inc - Plainview	131,985	William	Arendt	5075343141	Plainview	MN	55964
15700015	Federal-Mogul Corp Powertrain Systems	129,810	Ron	Koller	6513454541	Lake City	MN	55041
3100002	Hedstrom Lumber Co Inc - Grand Marais	129,792	Howard	Hedstrom	2183872995	Grand Marais	MN	55604
12300019	Minnesota Brewing Co	129,753	Michael	Hime	6512289173	St Paul	MN	55102
10900022	Crenlo Inc - Plant 3	129,068						
7900022	Seneca Foods Corp - Montgomery	127,026	Tim	Nelson	5073648641	Montgomery	MN	56069
5300312	Superior Plating	124,632	Jayne	Lecy	6123792121	Minneapolis	MN	55413
2700043	Concordia College - Moorhead Campus	121,144	Ansel	Hakanson	2182993362	Moorhead	MN	56562
4900065	Bergquist Co - Cannon Falls	120,200				Cannon Falls	MN	
5300293	Fairview Southdale Hospital	118,372	David	Fashant	6129241394	Edina	MN	55435
13500008	Polaris Industries LP	116,801						
16300025	3M - Cottage Grove Corp Incinerator	114,236						
1500009	Kraft Foods - New Ulm	113,348	Denise	Manderfeld	5073544131	New Ulm	MN	56073
5300048	ADM Milling Co - A Mill	112,071	Cyrus	Irani	6126278000	Minneapolis	MN	55414
3700011	Koch Petroleum Group LP - Pine Bend	110,916				Pine Bend		
5300384	Banta Catalog - Minneapolis	109,981				Minneapolis		
13900005	Anchor Glass Container Corp - Shakopee	107,835				Shakopee		
5300251	Interplastic Corp - Minneapolis Plant	106,763	Sheri	Peterson	6514816860	Minneapolis	MN	55413-1775
14700012	Crown Cork & Seal Co Inc - Owatonna	104,148	Graham	Foulkes	5074551344	Owatonna	MN	55060
8500032	Hutchinson Technology	102,762	Richard	Higgins	3205871950	Hutchinson	MN	55350
10300001	St Peter Regional Treatment Center	102,700	Dave	Woelpern	5079317280	St Peter	MN	56082
12300108	Hamline University	101,102	Mike	Waterbury	6515232227	St Paul	MN	55104
12300386	3M - Abrasives Systems Division	100,954						
8500035	Seneca Foods Corp - Glencoe	99,729	Arlen	Aas	3208642253	Glencoe	MN	55336
12300054	American National Can - St Paul (Eva)	99,691				St. Paul	MN	55107

Appendix F – Survey and Cover Letter

August 31, 2000

<salut> <firstname> <lastname>
<title>
<address_a>
<address_b>
<address_c>
<city>, <state> <zip>

Dear <salut> <lastname>:

The Minnesota Environmental Quality Board (MEQB) is currently assessing the potential for combined heat and power (CHP), also known as cogeneration, in Minnesota. While many industrial and institutional facilities already have CHP systems in place, the MEQB is interested in identifying untapped CHP potential. Further developing Minnesota's CHP potential could have significant economic and environmental benefits for individual firms and for Minnesota as a whole. We have retained Kattner/FVB District Energy Inc. to assist us with this project.

As part of this project, the MEQB is developing an inventory of high-potential CHP sites. This inventory will be used to assess the potential for CHP at individual facilities, and will be available to policy makers and CHP developers. As part of our initial screening we have identified more than one hundred facilities that, based on facility type and fuel use, appear to have some CHP potential. The attached survey will gather additional information necessary to assess CHP potential. In order to minimize the burden on survey respondents, we have made every attempt to keep the survey as brief as possible. Please take a few minutes to fill out the attached survey and return to me by fax at 651/296-3698 or my mail. The completed survey can be returned to me by fax or mail. If it is more convenient for you, you can also fill out a copy at our agency's website, www.mnplan.state.mn.us/eqb/powersurvey.htm .

If we have not received your response by September 15, you will receive a follow-up call. If you have any questions or concerns about either the survey or the project please do not hesitate to contact me by phone at 651/296-2878, or by e-mail at suzanne.steinhauer@state.mn.us.

Thank you for your assistance in this effort to enhance Minnesota's environmental and economic vitality.

Sincerely,

Suzanne Steinhauer
Energy Facilities Planner

Minnesota Cogeneration Survey

Name:____.
Address:____.
Company:____Title: ____________________.
Telephone Number:________________________________ Fax Number:______________.
Date:______________Email address:____.

1. Electric Generation:

1.1 Existing electric generation

Type	Capacity	Fuel	Age	Cogen

1.2. Plans for additional electric generation:____
____.

1.3. Annual electricity generation (MWH):_______________________________________.

1.4. Peak electricity demand (MW):____.

1.5. Annual electric consumption (MWH):______________________________________.

1.6. Sources and costs of electric power:____
____.

2. Thermal Energy Generation:

2.1. Existing thermal generation equipment

Type	Capacity (mmbtu/hr)	Fuel	Age

2.2. Plans for additional thermal generation:______________________________________
____.

2.3. Peak thermal energy demand (mmbtu/hr):______________________________.

2.4. Potential nearby additional thermal loads:______________________________.

2.5. Annual thermal energy consumption (mmbtu):__________________________.

2.6. Breakdown of thermal requirements

Use of Heat					
Temperature (F)					
Pressure (psig)					
Peak demand (mmbtu/hr)					

3. General:

3.1. Fuel costs:____.

3.2. Natural Gas availability:____.

3.3. Access to electric transmission grid:__________________________________.

3.4. How much space is available for cogeneration facilities inside the plant:___________
____.
Outside the plant:____.

3.5. Annual fuel consumption by fuel type:

Fuel	Unit	Annual consumption
Natural gas	MCF	
Coal	Mmbtu	
Light fuel oil	Gallons	
Residual oil	Gallons	
Other		
Other		
Other		

Appencix G: Survey Data

Appendix G: Survey Data – Contact Information

Company	Name	Telephone	Fax	E-mail
SMDC Health Systems	John Rice	218-786-4693	218-786-2475	
Crown Cork & Seal	Mark Fink	507-455-8167	507-455-1344	
Ford Motor Company	Brad Bystrom	651-696-0660	651-696-0523	BBystrom@Ford.com
ACS - Crookston	Annette Cederberg	218-236-4304	218-236-4365	
ACS - East Grand Forks	Annette Cederberg	218-236-4304	218-236-4365	
Duluth Steam Cooperative	Gerald W Pelofske	218-923-3601	218-723-3600	
Ridgewater College	Tom Wilts	320-231-5133	320-231-5498	twilts@ridgewatermnscu.edu
Froedtert Malt	David L Brunette	414-649-0284	414-649-0295	dbrunette@froedtermalt.com
American Crystal Sugar Co - Moorhead	Annette Cederberg	218-236-4304	218-236-4365	acederbe@crystalsugar.com
Louisiana Pacific Corporation	Barbara Hamilton	218-834-5652	218-834-2363	Barbara.Hamilton@LPCorp.com
Order of St Benedict Inc. St Johns University	Attn: Power Plant	320-363-2541	320-363-3999	
Seneca Food Corp (Glencoe)	Daniel Roe	320-864-2251	320-864-5779	droe@senecafoods.com
Dairy Farmers of America	Radu Rasidescu	507-732-8642	507-732-8669	
Interplastic Corp	Gary Severson	651-481-6861	612-331-4235	Gseverson@Interplastic.com
Fergus Falls Regional Treatment Center	John H Wright	218-739-7322	218-739-7570	john.h.wright@state.mn.us
Hormel Foods Corp	Chad Sayles	507-437-5415	507-437-5524	cbsayles@hormel.com
Chippewa Valley Ethanol Company	Mitch T Miller	320-843-1235	320-843-1239	MJMILLER@cvec.com
Seneca Foods Corp	Jim HauKom	507-280-4500	507-280-4579	JHauKom@senecafood.com
St Olaf College	Perry Kruse	507-646-3280		kruse@stolaf.edu
Northwood Panelboard	Jack Wallingford	218-751-2023	218-751-2075	
North Star Steel	Todd Ebersviller	651-731-5697	651-731-5699	
New Ulm Public Utilities	Robert Stevenson	507-359-8264	507-354-7318	nupuc@newulmtel.net
Brown Printing Co	Dean Veldboom	507-835-0289	507-835-0180	dean.veldboom@bpc.com
Diamond Brands Inc	Patrick Wippler	218-878-2744	218-879-6369	pwippler@diamondbrands.com
Boise Cascade	Jay Lofgren	218-285-5218	218-285-5691	Jay_LoFgren@BC.com
Potlatch Corporation	Julie Hendricks	218-828-6522	218-828-5118	
Heartland Corn Products	Ben Brown	507-647-5000	507-647-5010	ben@mean.net
Marvin Windows and Doors	Bradley J Baumann	218-386-1430	218-3864046	bradbau@marvin.com
US Steel - Minnesota Ore Operations	Raymond Potts	218-749-7598	218-749-7360	rpotts@uss.com
Blandin Energy Center	Tim St. Cyr	218-326-1622	218-326-1161	tstcyr@mnpower.com
Brainerd Regional Human Services	Ron Ledin	218-828-2627	218-828-6096	
Rahr Malting Co	Paul Kramer	952-496-7002	952-496-7055	pkramer@rahr.com
Ag Processing Inc	Lee Gunderson	320-769-4386	320-169-2668	

Appendix G: Survey Data – Summary Assessment

Site	Summary Assessment
St. Mary's Duluth Clinic (SMDC) Health Systems	Good prospect for cogeneration, with good data.
Crown Cork & Seal	Potential prospect, but data are inadequate for assessment.
Ford Motor Company	Large hydroelectric capacity and poor thermal load factor makes this a poor prospect for cogeneration.
ACS - Crookston	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
ACS - East Grand Forks	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Duluth Steam Cooperative	Good prospect for cogeneration, with good data.
Ridgewater College	Small size makes this a poor prospect, data are incomplete.
Froedtert Malt	Potential prospect, but data are inadequate for assessment.
American Crystal Sugar Co - Moorhead	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Louisiana Pacific Corporation	Wide mix of process requirements and equipment, and access to inexpensive wood fuel and relatively small size for solid fuel cogeneration makes this a difficult prospect for cogeneration.
Order of St Benedict Inc. St Johns University	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Seneca Food Corp -- Glencoe	Good prospect for cogeneration, with good data.
Dairy Farmers of America	Potential prospect, but data are inadequate for assessment.
Interplastic Corp	Wide mix of process requirements and poor electric load factor makes this a difficult prospect for cogeneration.
Fergus Falls Regional Treatment Center	Small size and outside purchase of steam makes this a poor prospect, and data are incomplete.
Hormel Foods Corp	Good prospect for cogeneration, with good data.
Chippewa Valley Ethanol Company	Poor thermal load factor makes this a poor prospect for cogeneration.
Seneca Foods Corp -- Rochester	Potential prospect, but data are inadequate for assessment.
St Olaf College	Potential prospect, but data are inadequate for assessment.
Northwood Panelboard	Access to inexpensive wood fuel makes this a difficult prospect for cogeneration.
North Star Steel	Direct-fired processes eliminates this as a cogeneration prospect.
New Ulm Public Utilities	Already has cogeneration; prospects for additional economical cogeneration is unlikely.
Brown Printing Co	Direct-fired processes eliminates this as a cogeneration prospect.
Diamond Brands Inc	Good prospect for cogeneration, with good data.
Boise Cascade	Already has cogeneration but considering adding more, with good data.
Potlatch Corporation -- Brainerd	Already small cogeneration but thermal and power loads may support more; data are incomplete.
Heartland Corn Products	Potential prospect, but data are inadequate for assessment.
Marvin Windows and Doors	Low cost power makes this a poor prospect for cogeneration.
US Steel - Minnesota Ore Operations	Potential prospect, but data are inadequate for assessment.
Blandin Energy Center	Already cogeneration but thermal and power loads may support more; data are incomplete.
Brainerd Regional Human Services	Small size and existing back-up generation makes this a poor prospect; data are incomplete.
Rahr Malting Co	Good prospect for cogeneration, with good data.
Ag Processing Inc	Small size makes this a poor prospect, data are incomplete.

Appendix G: Survey Data – Electric & Thermal Summary

Company	Existing Elec. Generation Total capacity-kW	Peak Power Demand MW	Electric Load Factor EFLH	Peak thermal Demand MMBTU/Hr	Thermal Load Factor EFLH	Ratio Peak Electric to Peak Thermal Demand	Ratio Avg Electric to Avg Thermal Demand
SMDC Health Systems	4,340	3.4	4,118	36	3,889	0.322	0.341
Crown Cork & Seal		7.8	236				
Ford Motor Company	18,000	15.6	6,077	88	1,870	0.605	1.966
ACS - Crookston	6,900	11.3	1,327	242		0.159	
ACS - East Grand Forks	8,200	17.4	5,724	388		0.153	
Duluth Steam Cooperative	950	0.75	3,196	270	3,147	0.009	0.010
Ridgewater College		1.7	2,508				0.662
Froedtert Malt							
American Crystal Sugar Co - Moorhead	6,200	11.7	4,957	242		0.165	
Louisiana Pacific Corporation		3.1	7,235	80	1,370	0.132	0.698
Order of St Benedict Inc. St Johns University	1,900	2.5		73		0.117	
Seneca Food Corp (Glencoe)		9.7	1,876	90	982	0.368	0.702
Dairy Farmers of America							0.000
Interplastic Corp	40	0.005	1,060	35	3,714	0.000	0.000
Fergus Falls Regional Treatment Center	1,000	0.85	4,235	20	3,673	0.148	0.171
Hormel Foods Corp		19	5,789	160		0.405	
Chippewa Valley Ethanol Company	3,000	3.4	6,000	110	5,602	0.105	0.113
Seneca Foods Corp		4.6	1,983	182		0.086	
St Olaf College	4,000	3.8	4,474				
Northwood Panelboard		5.6	7,679	150	282	0.127	3.463
North Star Steel							
New Ulm Public Utilities	47,000	48.1	6,682	39	2,564	4.208	10.966
Brown Printing Co		9.2	6,576	36	6,425	0.877	0.897
Diamond Brands Inc		1.63	5,764	20	7,662	0.278	0.209
Boise Cascade	43,640	70	7,571	1,800	6,111	0.133	0.164
Potlatch Corporation	3,500	13	8,478				0.330
Heartland Corn Products							
Marvin Windows and Doors	7,400	6.4	3,281	33	5,988	0.654	0.358
US Steel - Minnesota Ore Operations							
Blandin Energy Center	34,000	90	8,096	890	4,096	0.345	
Brainerd Regional Human Services	900	1.39	4,861				
Rahr Malting Co	400	12.4	5,242	160	6,666	0.264	0.208
Ag Processing Inc		3.2					

Appendix G: Survey Data – Electric Generation

Company	Electric Generation							Capacity to Demand Percentage
	Type	Quantity	Total Cap. (kW)	Fuel Type	Min age - yrs	Max age -yrs	Co-gen	
SMDC Health Systems	Diesel engine	4	4,340	Diesel	10	36	no	128%
Crown Cork & Seal								
Ford Motor Company	Hydroelectric	1	18,000	Water	75	75	no	115%
ACS - Crookston	Steam Turbines		6,900	Coal	45	45	yes	61%
ACS - East Grand Forks	Steam Turbines		8,200	Coal	80	80	yes	47%
Duluth Steam Cooperative	Cummings Generation	1	950	Diesel	5	5	no	127%
Ridgewater College								
Froedtert Malt								
American Crystal Sugar Co - Moorhead	Steam Turbines		6,200	Coal	50	50	yes	53%
Louisiana Pacific Corporation								
Order of St Benedict Inc. St Johns University	Steam Turbines & (1) Diesel	5	1,900	#2 Fuel	47	53	yes	76%
Seneca Food Corp (Glencoe)								
Dairy Farmers of America								
Interplastic Corp	Ford Engine	1	40	Natural Gas	10	10	no	800%
Fergus Falls Regional Treatment Center	Emergency Generator	1	1,000	#2 Diesel	5	5	no	118%
Hormel Foods Corp								
Chippewa Valley Ethanol Company	Cummings Diesel	2	3,000	Diesel	4.5	4.5	no	88%
Seneca Foods Corp								
St Olaf College		1	4,000	Diesel	3	3	no	105%
Northwood Panelboard								
North Star Steel								
New Ulm Public Utilities	Steam	4	47,000	Coal, Gas, Oil	3	43	yes	98%
Brown Printing Co								
Diamond Brands Inc								
Boise Cascade	Turbines & Waterwheel	12	43,640	Gas, Water	43	73	yes	62%
Potlatch Corporation	Hydro & Steam Turbine	2	3,500	Water, Gas, Coal	42	84	yes	27%
Heartland Corn Products								
Marvin Windows and Doors	Diesel Generators	12	7,400	Diesel			no	116%
US Steel - Minnesota Ore Operations								
Blandin Energy Center	Steam Turbine	2	34,000	Wood, Coal, Gas	20	31	yes	38%
Brainerd Regional Human Services	Diesel engine	3	900	Diesel	10	42	no	65%
Rahr Malting Co		1	400	Fuel Oil	1	1	no	3%
Ag Processing Inc								

Appendix G: Survey Data – Electric Summary

Company	Plans for additional electric generation	Annual electric generation MWH	Peak demand MW	Annual Consumption MWH	Electric Load Factor EFLH	Average Electric Demand KW/hr
SMDC Health Systems	no	Standby	3.4	14,000	4,118	1,598
Crown Cork & Seal	no	None	7.8	1,840	236	210
Ford Motor Company	no	117.3	15.6	94,800	6,077	10,822
ACS - Crookston	no	39,000	11.3	15,000	1,327	1,712
ACS - East Grand Forks	no	50,600	17.4	99,600	5,724	11,370
Duluth Steam Cooperative	yes 2004	None	0.75	2,397	3,196	274
Ridgewater College	yes	None	1.7	4,264	2,508	487
Froedtert Malt				23,931		2,732
American Crystal Sugar Co - Moorhead	no	35,000	11.7	58,000	4,957	6,621
Louisiana Pacific Corporation	no		3.1	22,428	7,235	2,560
Order of St Benedict Inc. St Johns University	yes	300	2.5		0	
Seneca Food Corp (Glencoe)	Possible		9.7	18,198	1,876	2,077
Dairy Farmers of America						
Interplastic Corp	no	Emergency	0.005	5.3	1,060	1
Fergus Falls Regional Treatment Center	no	Emergency	0.85	3,600	4,235	411
Hormel Foods Corp	no		19	110,000	5,789	12,557
Chippewa Valley Ethanol Company	Future	450	3.4	20,400	6,000	2,329
Seneca Foods Corp			4.6	9,124	1,983	1,042
St Olaf College	no	70	3.8	17,000	4,474	1,941
Northwood Panelboard	no		5.6	43,000	7,679	4,909
North Star Steel						
New Ulm Public Utilities	yes 5/2001	16,916	48.1	321,404	6,682	36,690
Brown Printing Co	Reviewing	None	9.2	60,500	6,576	6,906
Diamond Brands Inc	no		1.63	9,396	5,764	1,073
Boise Cascade	Considering	230,000	70	530,000	7,571	60,502
Potlatch Corporation	no	20,431	13	110,219	8,478	12,582
Heartland Corn Products				30,000		3,425
Marvin Windows and Doors	Possibly	1,200	6.4	21,000	3,281	2,397
US Steel - Minnesota Ore Operations	no					
Blandin Energy Center	no	155,520	90	728,640	8,096	83,178
Brainerd Regional Human Services	yes		1.39	6,757	4,861	771
Rahr Malting Co	yes	0	12.4	65,000	5,242	7,420
Ag Processing Inc	no		3.2			

Appendix G: Survey Data – Electric Supplies & Costs

Company	Electric Power Sources	Cost Demand ($/KW)	Energy Costs ($/Kwh)	Average Cost ($/kWh)
SMDC Health Systems	Minnesota Power			0.048
Crown Cork & Seal	Owatonna Public Utilities			
Ford Motor Company	NSP			0.041
ACS - Crookston	Ottertail Power			0.038
ACS - East Grand Forks	City Power			0.049
Duluth Steam Cooperative	Minnesota Power			0.05
Ridgewater College	Willmar Municipal Utilities			0.0383
Froedtert Malt				
American Crystal Sugar Co - Moorhead				0.037
Louisiana Pacific Corporation	Cooperative Light & Power			0.01
Order of St Benedict Inc. St Johns University	NSP			
Seneca Food Corp (Glencoe)	Glencoe Municipal Electric & Mclead Coop Power			0.052 & 0.065
Dairy Farmers of America				
Interplastic Corp	NSP	Sum-9.26 Win-6.61	0.031	
Fergus Falls Regional Treatment Center	Western Area Power Administration			
Hormel Foods Corp	Austin Utilities			
Chippewa Valley Ethanol Company	Agralite Rural Electric Coop/Great River Energy	6.2		0.025
Seneca Foods Corp		11.213		0.0358
St Olaf College	NSP	2.54	0.0305	
Northwood Panelboard	Ottertail Power			0.037
North Star Steel				
New Ulm Public Utilities				
Brown Printing Co	NSP			
Diamond Brands Inc	Minnesota Power			0.045
Boise Cascade	Minnesota Power			
Potlatch Corporation	Minnesota Power			
Heartland Corn Products				
Marvin Windows and Doors	City of Warroad Minnkota Power			0.026
US Steel - Minnesota Ore Operations				
Blandin Energy Center	Minnesota Power & Blandin Energy Center			
Brainerd Regional Human Services	City Power & Light			0.041
Rahr Malting Co	NSP			0.043
Ag Processing Inc	Ottertail power company			

Appendix G: Survey Data – Thermal Generation

Company	Thermal Generation Type	Quantity	Capacity total MMBTUH	Fuel	Min Age - Years	Max Age - Years
SMDC Health Systems	Boilers	3	66	Natural gas	32	36
Crown Cork & Seal						
Ford Motor Company	Boilers	2	160	Gas, Propane, #6 Fuel	44	76
ACS - Crookston	Steam Turbine		334.3	Coal		
ACS - East Grand Forks	Steam Turbine		644.4	Coal		
Duluth Steam Cooperative	Boilers	1	38.8	Coal or Gas	68	68
Ridgewater College	Bolier	6	46	Natural gas, Oil	10	32
Froedtert Malt						
American Crystal Sugar Co - Moorhead	Steam Turbine		300.4	Coal		
Louisiana Pacific Corporation	Oil Heater, Woodburner, Ovens	7	107	Wood, Natural Gas	3	15
Order of St Benedict Inc. St Johns University	Boilers	6	165	Natural Gas, #2 Fuel, Coal	2	53
Seneca Food Corp (Glencoe)	Boilers	3	118	Natural Gas or #2 Fuel	23	52
Dairy Farmers of America		2	83	Natural Gas & Fuel Oil #6	20	20
Interplastic Corp	Boilers, Oxidizer, Process Reactor	8	66	Natural Gas & Propane	1	35
Fergus Falls Regional Treatment Center	Boiler (not in use)	2	92	Coal, Oil-Gas	30	45
Hormel Foods Corp	Boilers	3		Natural Gas, #6 Fuel Oil	2	20
Chippewa Valley Ethanol Company	Boiler, Dryer	3	160	Natural Gas, Propane	1	4.5
Seneca Foods Corp	Boiler	4	147	Natural Gas, Fuel Oil	21	44
St Olaf College	Boilers			Natural Gas, Oil	30	30
Northwood Panelboard	Konus, Lamb, Wellons	5	200	Hog Fuel	4	19
North Star Steel						
New Ulm Public Utilities	Boiler	3	290	Natural Gas, Coal	35	52
Brown Printing Co						
Diamond Brands Inc	Boiler	4	32	Waste Wood & Bark	66	66
Boise Cascade	Boiler	3	2221	Gas, Bark, Sludge, Black Liquor	24	50
Potlatch Corporation	Steam Turbine	1	49.5	Coal, Gas	42	42
Heartland Corn Products						
Marvin Windows and Doors	Boiler	4	104.3	Wood, Natural Gas		
US Steel - Minnesota Ore Operations	Boilers	5	496	Natural Gas, Fuel Oil	22	33
Blandin Energy Center	Boiler	4	1100	Wood, Coal, Gas	0	20
Brainerd Regional Human Services						
Rahr Malting Co	Air to Air Heaters, Boilers	26	308	Natural Gas, Propane	5	20
Ag Processing Inc						

Appendix G: Survey Data – Thermal Summary

Company	Plans for additional thermal generation	Peak thermal demand MMBTU/Hr	Nearby potential loads	Annual thermal consumption MMBTU	Thermal Load Factor EFLH	Average Thermal Demand MMBtu/hr
SMDC Health Systems	no	36	office buildings	140,000	3,889	16
Crown Cork & Seal	no					
Ford Motor Company	no	88		164,520	1,870	19
ACS - Crookston	no	242	None		0	0
ACS - East Grand Forks	no	388	None		0	0
Duluth Steam Cooperative		270		849,731	3,147	97
Ridgewater College	no			21,973		3
Froedtert Malt						
American Crystal Sugar Co - Moorhead	no	242	None		0	0
Louisiana Pacific Corporation	no	80	None	109,599	1,370	13
Order of St Benedict Inc. St Johns University	no	73	None		0	
Seneca Food Corp (Glencoe)	no	90	Unknown	88,400	982	10
Dairy Farmers of America	no			152,726		17
Interplastic Corp	no	35	None	130,000	3,714	15
Fergus Falls Regional Treatment Center	no	20	Unknown	72,000	3,673	8
Hormel Foods Corp	no	160	None		0	
Chippewa Valley Ethanol Company	Possible	110	None	616,250	5,602	70
Seneca Foods Corp	no	182	None		0	
St Olaf College	no					
Northwood Panelboard	no	150	None	42,360	282	5
North Star Steel						
New Ulm Public Utilities	no	39	39 MMBTU/Hr	100,000	2,564	11

Brown Printing Co	no	36	None	230,000	6,425	26
Diamond Brands Inc	no	20	None	153,230	7,662	17
Boise Cascade	no	1,800	None	11,000,000	6,111	1,256
Potlatch Corporation	no			1,139,588		130
Heartland Corn Products						
Marvin Windows and Doors	no	33		200,000	5,988	23
US Steel - Minnesota Ore Operations	no					
Blandin Energy Center	no	890	None	3,645,565	4,096	416
Brainerd Regional Human Services						
Rahr Malting Co	no	160	None	1,066,500	6,666	122
Ag Processing Inc	no					

Appendix G: Survey Data – Thermal Requirements (p. 1 of 2)

Company	Breakdown of Thermal Requirements								
	Space Heating			Dryer			Hot Water		
	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH
SMDC Health Systems	10		30				10		5
Crown Cork & Seal									
Ford Motor Company	175	375	88						
ACS - Crookston									
ACS - East Grand Forks									
Duluth Steam Cooperative	225	397	270						
Ridgewater College									
Froedtert Malt									
American Crystal Sugar Co - Moorhead									
Louisiana Pacific Corporation		70	31		260	40			
Order of St Benedict Inc. St Johns University									
Seneca Food Corp (Glencoe)	15	250	15						
Dairy Farmers of America									
Interplastic Corp									
Fergus Falls Regional Treatment Center									
Hormel Foods Corp									
Chippewa Valley Ethanol Company	65	315							
Seneca Foods Corp									
St Olaf College									
Northwood Panelboard		400	10		380	100			
North Star Steel									
New Ulm Public Utilities	15	250	23						
Brown Printing Co		75			400				
Diamond Brands Inc	12	213	10						
Boise Cascade	40	260	200	165	410	600			
Potlatch Corporation									
Heartland Corn Products									
Marvin Windows and Doors									
US Steel - Minnesota Ore Operations									
Blandin Energy Center									
Brainerd Regional Human Services									
Rahr Malting Co		75	125						
Ag Processing Inc									

Appendix G: Survey Data – Thermal Requirements (p. 2 of 2)

Company	Breakdown of Thermal Requirements								
	Electric Generation			Processing			Sterilizes/Steam		
	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH	Pres - Psig	Temp - F	Demand - PPH
SMDC Health Systems							60		1
Crown Cork & Seal									
Ford Motor Company									
ACS - Crookston							400	560	242
ACS - East Grand Forks							400	560	388
Duluth Steam Cooperative									
Ridgewater College									
Froedtert Malt									
American Crystal Sugar Co - Moorhead							400	560	242
Louisiana Pacific Corporation					240	35			
Order of St Benedict Inc. St Johns University									
Seneca Food Corp (Glencoe)				28	265	95			
Dairy Farmers of America				150	352				
Interplastic Corp					430	10	100	350	0.27
Fergus Falls Regional Treatment Center									
Hormel Foods Corp							125 & 15	Saturated	120 & 80
Chippewa Valley Ethanol Company									
Seneca Foods Corp					200				
St Olaf College									
Northwood Panelboard					400	30			
North Star Steel									
New Ulm Public Utilities				140	350	16			
Brown Printing Co									
Diamond Brands Inc				149	334	10			
Boise Cascade				40	260	200			
Potlatch Corporation				100	750	49.5			
Heartland Corn Products							125		
Marvin Windows and Doors							12	244	33.4
US Steel - Minnesota Ore Operations									
Blandin Energy Center	1250	900	270	50, 150, 400	320, 500, 700	540, 90, 270			
Brainerd Regional Human Services									
Rahr Malting Co				<15 psig	175-240	150			
Ag Processing Inc									

Appendix G: Survey Data – Fuel Costs

Company	Natural Gas per MCF	No. 2 Oil per Gal.	No.6 Oil per Gal	Diesel per Gal	Propane per Gal	Wood per ton	Coal per ton
SMDC Health Systems	$3.00	$0.40					
Crown Cork & Seal							
Ford Motor Company	$3.00						
ACS - Crookston							$9.34
ACS - East Grand Forks							$9.34
Duluth Steam Cooperative							$21.97
Ridgewater College	$4.30	$0.90					
Froedtert Malt							
American Crystal Sugar Co - Moorhead							$9.34
Louisiana Pacific Corporation	$3.63					$5.64	
Order of St Benedict Inc. St Johns University	High	$0.90					$40.00
Seneca Food Corp (Glencoe)	Varies						
Dairy Farmers of America	$4.56		$0.50				
Interplastic Corp	$4.78				$0.45		
Fergus Falls Regional Treatment Center							
Hormel Foods Corp	$3.00		$0.45				
Chippewa Valley Ethanol Company	$3.63			$1.05	$0.95		
Seneca Foods Corp	$3.07						
St Olaf College	$4.46		$0.43	$1.00			
Northwood Panelboard	$2.60				$0.30		
North Star Steel							
New Ulm Public Utilities	$4.20						$49.50
Brown Printing Co							
Diamond Brands Inc						$20.00	
Boise Cascade							
Potlatch Corporation	$4.75						$59.00
Heartland Corn Products							
Marvin Windows and Doors	$5.90					$10.00	
US Steel - Minnesota Ore Operations							
Blandin Energy Center							
Brainerd Regional Human Services	$4.00		$0.50				
Rahr Malting Co	$5.00						
Ag Processing Inc							

Appendix G: Survey Data – Fuel Consumption

Company	Natural Gas MCF	No. 2 Fuel Oil Gallons	No. 6 Fuel Oil Gallons	Propane Gal	Refuse tons	Wood tons	Diesel Gal	Coal tons
SMDC Health Systems	135,000	36,000						
Crown Cork & Seal	1							
Ford Motor Company	970							
ACS - Crookston								98,000
ACS - East Grand Forks								180,000
Duluth Steam Cooperative								79,141
Ridgewater College	20,440	5,000						
Froedtert Malt	336,032							
American Crystal Sugar Co - Moorhead								104,000
Louisiana Pacific Corporation	147					27,363		
Order of St Benedict Inc. St Johns University	90	3,000						9,800
Seneca Food Corp (Glencoe)	125,000	>5,000						
Dairy Farmers of America	218,904		12,191					
Interplastic Corp	130,000			45,000				
Fergus Falls Regional Treatment Center					30,000			
Hormel Foods Corp	550,000		1,200,000					
Chippewa Valley Ethanol Company	725,000			75,000				
Seneca Foods Corp	136,144							
St Olaf College	163,000		20,515					
Northwood Panelboard	70,000			155,000				
North Star Steel								
New Ulm Public Utilities	518,000	195,603						
Brown Printing Co	225,000							
Diamond Brands Inc						15,323		
Boise Cascade	4,800,000							
Potlatch Corporation	1,460,000							170
Heartland Corn Products	1,200,000							
Marvin Windows and Doors	12,500					15,000	35,000	
US Steel - Minnesota Ore Operations	7,338,000	144,828				86,355		
Blandin Energy Center	1,400,000					350,000		32,000
Brainerd Regional Human Services	114,373		80,011					
Rahr Malting Co		1,185,000						
Ag Processing Inc								

Appendix G: Survey Data – Expandability

Company	Natural gas utility pressure available	Space Available for Cogeneration Facilities	
		Inside Plant	Outside Plant
SMDC Health Systems		None	Parking lots
Crown Cork & Seal		None	
Ford Motor Company	60	None	Adequate
ACS - Crookston	160	None	Limited
ACS - East Grand Forks	160	Limited	Limited
Duluth Steam Cooperative	15	Some	Adequate
Ridgewater College		Limited	Adequate
Froedtert Malt			
American Crystal Sugar Co - Moorhead	160	Limited	Some
Louisiana Pacific Corporation	50	Unknown	Unknown
Order of St Benedict Inc. St Johns University	30	Some	
Seneca Food Corp (Glencoe)	25	None	5 Acres
Dairy Farmers of America		None	Adequate
Interplastic Corp	3	None	None
Fergus Falls Regional Treatment Center		Limited	Adequate
Hormel Foods Corp		None	10000 sq ft
Chippewa Valley Ethanol Company	94	Limited	125+ Acres
Seneca Foods Corp	10	Limited	
St Olaf College	60	None	None
Northwood Panelboard	100	None	Some
North Star Steel		None	None
New Ulm Public Utilities	300	No need	None
Brown Printing Co	300-400	None	Some
Diamond Brands Inc		None	Adequate
Boise Cascade	400	Limited	
Potlatch Corporation	43	None	None
Heartland Corn Products			100 Acres
Marvin Windows and Doors			
US Steel - Minnesota Ore Operations			
Blandin Energy Center	100 & 200	Limited	None
Brainerd Regional Human Services	10	None	None
Rahr Malting Co	800		2-3 acres
Ag Processing Inc		None	None

Appendix H: Site Assessments

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Operating Parameters

Throttle steam pressure (psig)	600	In-house biomass available (tons)	58,000
Throttle steam temperature (F)	750	Heating value (Btu/lb)	7,943
Backpressure steam pressure (psig)	50	Available MMBtu/year in-house	921,388
Btu per pound required in boiler	1,058	Additional biomass required	616,117
Boiler efficiency	85%		
Throttle steam quantity (pounds/hour)			
Peak	196,192		
At average thermal load	145,500		
Peak power output (MW)			
Gross	9.308		
Net	8.377		
Net as % of peak demand	68%		
Average power output (MW)			
Gross	6.903		
Net	6.213		

Hourly thermal and electric production

	Average thermal	Peak
Fuel use (MMBtu)	181	244
Thermal energy produced (MMBtu)	125	168
Thermal energy produced (% of peak demand)	78%	105%
Fuel displaced (MMBtu)	147	198
Displaced electricity (kWh)	6,213	8,377
Displaced electricity (% of peak demand)	50%	68%
Total efficiency (%)	81%	81%

Annual operations

Target full load hours of operation	7,000	7,000	7,000	7,000
Percent availability	90%	90%	90%	90%
Adjusted full load hours	6,300	6,300	6,300	6,300
Electric output (MWh)	52,776	52,776	52,776	52,776
Thermal output (MMBtu)	1,061,388	1,061,388	1,061,388	1,061,388
Fuel consumption (MMBtu)	1,537,505	1,537,505	1,537,505	1,537,505
Total electricity consumed (MWh)	65,000	65,000	65,000	65,000
Electricity generated (MWh)	52,776	52,776	52,776	52,776
Electricity purchased (MWh)	12,224	12,224	12,224	12,224
Electricity sold (MWh)	-	-	-	-
Assumed value of electricity sold ($/MWh)	$ 15.0	$ 15.0	$ 15.0	$ 15.0

Total thermal energy consumed (MMBtu)	1,066,500	1,066,500	1,066,500	1,066,500
Thermal energy generated with CHP (MMBtu)	1,061,388	1,061,388	1,061,388	1,061,388
Thermal energy generated with non-cogen boiler	5,112	5,112	5,112	5,112

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Steam Turbine CHP -- Biomass **8.38 MW net power output after station load**

Credit for boiler capacity?	**no**
Investment tax credit?	**no**
Renewable production credit?	**no**
Avoided natural gas cost ($/MMBtu)	**$ 5.00**

Economic Analysis with Sensitivity to Biomass Costs

Capital costs	
Capital cost ($/kW)	$ 2,400
Gross capital cost ($)	$ 22,339,200
Boiler capacity credited (MMBtu/hour)	-
Boiler capacity type	gas/oil
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000
Boiler capacity credit ($)	$ -
Investment tax credit (%)	0%
Investment tax credit ($)	$ -
Net capital cost ($)	$ 22,339,200

Operating costs				
Biomass fuel cost ($/MMBtu)	$4.00	$3.00	$2.00	$1.00
Avoided natural gas fuel cost ($/MMBtu)	$ 5.00	$5.00	$5.00	$5.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	8.0	8.0	8.0	8.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0140	$ 0.0140	$ 0.0140	$ 0.0140
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.045	$ 0.045	$ 0.045
Estimated increase in $/kWh purchased	20%	20%	20%	20%
Annual operating costs				
Fuel	$ 6,150,022	$ 4,612,516	$ 3,075,011	$ 1,537,505
Labor	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 738,869	$ 738,869	$ 738,869	$ 738,869
Additional cost for power purchased	$ 110,013	$ 110,013	$ 110,013	$ 110,013
Renewable energy production tax credit	$ -	$ -	$ -	$ -
Total	$ 7,398,903	$ 5,861,398	$ 4,323,893	$ 2,786,387
Annual savings				
Avoided fuel for thermal generation	$ 6,243,461	$ 6,243,461	$ 6,243,461	$ 6,243,461
Avoided electricity costs	$ 2,374,936	$ 2,374,936	$ 2,374,936	$ 2,374,936
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 8,618,397	$ 8,618,397	$ 8,618,397	$ 8,618,397

Net operating savings	$ 1,219,494	$ 2,756,999	$ 4,294,505	$ 5,832,010
Simple payback (years)	18.3	8.1	5.2	3.8

Appendix H-1: Rahr Malting, Option 1 Steam Turbine CHP –Biomass

Steam Turbine CHP -- Biomass **8.38 MW net power output after station load**

Economic Analysis with Sensitivity to Power Value at Biomass Cost of **$ 1.50 per MMBtu**
and Avoided Natural Gas Cost of **$ 5.00 per MMBtu**

Cost factors				
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.050	$ 0.055	$ 0.060
Estimated increase in $/kWh purchased	20%	20%	20%	20%
Annual operating costs				
Fuel	$ 2,306,258	$ 2,306,258	$ 2,306,258	$ 2,306,258
Labor	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 738,869	$ 738,869	$ 738,869	$ 738,869
Additional cost for power purchased	$ 110,013	$ 122,236	$ 134,460	$ 146,684
Renewable energy production tax credit	$ -	$ -	$ -	$ -
Total	$ 3,555,140	$ 3,567,364	$ 3,579,587	$ 3,591,811
Annual savings				
Avoided fuel for thermal generation	$ 6,243,461	$ 6,243,461	$ 6,243,461	$ 6,243,461
Avoided electricity costs	$ 2,374,936	$ 2,638,818	$ 2,902,700	$ 3,166,582
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 8,618,397	$ 8,882,279	$ 9,146,161	$ 9,410,043
Net operating savings	$ 5,063,257	$ 5,314,916	$ 5,566,574	$ 5,818,232
Simple payback (years)	4.4	4.2	4.0	3.8

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Operating Parameters	
Peak power output (MW)	
Gross	10.44
Net	9.92
Fuel input (MMBtu/hour) (HHV)	
Turbine	123.2
Full supplemental firing	106.0
Total	229.2
Thermal output (MMBtu/hour)	
Base	48.6
Full supplemental firing	150.0
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	123.2
Electricity out	33.8
Thermal out	48.6
Total out	82.4
Efficiency (HHV %)	66.9%
With supplemental firing	
Fuel in	229.2
Electricity out	33.8
Thermal out	150.0
Total out	183.8
Efficiency (HHV %)	80.2%
Equivalent Full Load Hours of operation	
Electric	6,350
Thermal including supplemental firing	5,953
Peak displaced electricity (% of peak demand)	80%
Thermal energy produced (% of peak demand)	
Without supplemental firing	30%
With supplemental firing	94%
Annual operations	
Electric output (MWh)	62,973
Thermal output (MMBtu)	
Power generation only	308,610
Supplemental firing	643,890
Total	952,500

Fuel consumption (MMBtu)	
Power generation only	743,502
Supplemental firing	673,525
Total	1,417,027
Total electricity consumed (MWh)	65,000
Electricity generated (MWh)	62,973
Electricity purchased (MWh)	2,027
% of electricity requirements generated	97%
Electricity sold (MWh)	-
% of electricity output sold	0%
Assumed value of electricity sold ($/MWh)	$ 15.0
Total thermal energy consumed (MMBtu)	1,066,500
Steam thermal energy consumed (MMBtu)	1,066,500
Thermal energy generated with cogen (MMBtu)	952,500
% of steam thermal produced with cogen	89%
Steam energy generated with non-cogen plant	114,000

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **9.92 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**			
Investment tax credit?	**no**			
Net metering?	**no**			
Capital costs				
Capital cost ($/kW)	$ 840			
Gross capital cost ($)	$ 8,768,760			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$8,768,760			
Operating costs				
Natural gas cost ($/MMBtu)	**$5.00**	**$4.00**	**$3.00**	**$2.00**
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	4.0	4.0	4.0	4.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0054	$ 0.0054	$ 0.0054	$ 0.0054
Avoided electricity cost ($/kWh)	$ 0.045	$ 0.045	$ 0.045	$ 0.045
Estimated increase in $/kWh purchased	40%	40%	40%	40%
Annual operating costs				
Fuel	$ 7,085,137	$ 5,668,110	$ 4,251,082	$ 2,834,055
Labor	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 340,056	$ 340,056	$ 340,056	$ 340,056
Additional cost for power purchased	$ 36,481	$ 36,481	$ 36,481	$ 36,481
Total	$7,661,674	$ 6,244,647	$ 4,827,619	$ 3,410,592
Annual savings				
Avoided fuel for thermal generation	$5,291,667	$ 4,233,333	$ 3,175,000	$ 2,116,667
Avoided electricity costs	$2,833,797	$ 2,833,797	$ 2,833,797	$ 2,833,797
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$8,125,464	$ 7,067,130	$ 6,008,797	$ 4,950,464
Net operating savings	$ 463,789	$ 822,484	$ 1,181,178	$ 1,539,872
Simple payback (years)	18.9	10.7	7.4	5.7

Appendix H-2: Rahr Malting
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **9.92 MW net power output**

Economic Analysis with Sensitivity to Avoided Power Costs

Assumes Natural Gas Cost of $ 5.00 per MMBtu

Cost factors				
Avoided electricity cost ($/kWh)	**$ 0.035**	**$ 0.045**	**$ 0.055**	**$ 0.065**
Revenue for electricity sold ($/kWh)	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Estimated increase in $/kWh purchased	40%	40%	40%	40%
Annual operating costs				
Fuel	$ 7,085,137	$ 7,085,137	$ 7,085,137	$ 7,085,137
Labor	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 340,056	$ 340,056	$ 340,056	$ 340,056
Additional cost for power purchased	$ 28,374	$ 36,481	$ 44,588	$ 52,695
Total	$ 7,653,567	$ 7,661,674	$ 7,669,781	$ 7,677,888
Annual savings				
Avoided fuel for thermal generation	$ 5,291,667	$ 5,291,667	$ 5,291,667	$ 5,291,667
Avoided electricity costs	$ 2,204,064	$ 2,833,797	$ 3,463,530	$ 4,093,262
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 7,495,731	$ 8,125,464	$ 8,755,196	$ 9,384,929
Net operating savings	$ (157,836)	$ 463,789	$ 1,085,415	$ 1,707,041
Simple payback (years)	(55.6)	18.9	8.1	5.1

Appendix H-3: Chippewa Valley Ethanol Option 1, Combustion Turbine CHP

Operating Parameters	
Peak power output (MW)	
Gross	3.42
Net	3.25
Fuel input (MMBtu/hour) (HHV)	
Turbine	47.2
Full supplemental firing	25.8
Total	73.0
Thermal output (MMBtu/hour)	
Base	17.9
Full supplemental firing	43.1
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	47.2
Electricity out	11.1
Thermal out	17.9
Total out	29.0
Efficiency (HHV %)	61.4%
With supplemental firing	
Fuel in	73.0
Electricity out	11.1
Thermal out	43.1
Total out	54.2
Efficiency (HHV %)	74.3%
Equivalent Full Load Hours of operation	
Electric	6,250
Thermal including supplemental firing	5,378
Peak displaced electricity (% of peak demand)	96%
Thermal energy produced (% of peak demand)	
Without supplemental firing	28%
With supplemental firing	66%
Annual operations	
Electric output (MWh)	20,300
Thermal output (MMBtu)	
Power generation only	111,875
Supplemental firing	237,677

Total		349,552
Fuel consumption (MMBtu)		
Power generation only		280,247
Supplemental firing		242,528
Total		522,775
Total electricity consumed (MWh)		20,400
Electricity generated (MWh)		20,300
Electricity purchased (MWh)		100
% of electricity requirements generated		100%
Electricity sold (MWh)		-
% of electricity output sold		0%
Assumed value of electricity sold ($/MWh)	$	15.0
Total thermal energy consumed (MMBtu)		611,106
Steam thermal energy consumed (MMBtu)		397,219
Thermal energy generated with cogen (MMBtu)		349,552
% of steam thermal produced with cogen		88%
Steam energy generated with non-cogen plant		47,666

Appendix H-3: Chippewa Valley Ethanol
Option 1, Combustion Turbine CHP

Combustion Turbine CHP **3.25 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**
Investment tax credit?	**no**
Net metering?	**no**

Capital costs				
Capital cost ($/kW)	$ 1,100			
Gross capital cost ($)	$ 3,760,900			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$ 3,760,900			
Operating costs				
Natural gas cost ($/MMBtu)	$5.00	$4.00	$3.00	$2.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	1.0	1.0	1.0	1.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0070	$ 0.0070	$ 0.0070	$ 0.0070
Avoided electricity cost ($/kWh)	$ 0.036	$ 0.036	$ 0.036	$ 0.036
Estimated increase in $/kWh purchased	0%	0%	0%	0%
Annual operating costs				
Fuel	$ 2,613,877	$ 2,091,102	$ 1,568,326	$ 1,045,551
Labor	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 142,102	$ 142,102	$ 142,102	$ 142,102
Additional cost for power purchased	$ -	$ -	$ -	$ -
Total	$ 2,805,979	$ 2,283,204	$ 1,760,428	$ 1,237,653
Annual savings				
Avoided fuel for thermal generation	$ 2,093,128	$ 1,674,503	$ 1,255,877	$ 837,251
Avoided electricity costs	$ 734,155	$ 734,155	$ 734,155	$ 734,155
Revenue from electricity sales	$ -	$ -	$ -	$ -
Total annual savings	$ 2,827,283	$ 2,408,657	$ 1,990,032	$ 1,571,406
Net operating savings	$ 21,304	$ 125,454	$ 229,603	$ 333,753
Simple payback (years)	176.5	30.0	16.4	11.3

Appendix H-4: Chippewa Valley Ethanol Option 2, Combustion Turbine CHP

Operating Parameters

Peak power output (MW)	
Gross	7.35
Net	6.98
Fuel input (MMBtu/hour) (HHV)	
Turbine	83.3
Full supplemental firing	31.8
Total	115.2
Thermal output (MMBtu/hour)	
Base	31.2
Full supplemental firing	62.4
Input/output calculation (MMBtu/hour)	
Without supplemental firing	
Fuel in	83.3
Electricity out	23.8
Thermal out	31.2
Total out	55.0
Efficiency (HHV %)	66.0%
With supplemental firing	
Fuel in	115.2
Electricity out	23.8
Thermal out	62.4
Total out	86.2
Efficiency (HHV %)	74.9%
Equivalent Full Load Hours of operation	
Electric	8,059
Thermal including supplemental firing	5,989
Peak displaced electricity (% of peak demand)	205%
Thermal energy produced (% of peak demand)	
Without supplemental firing	48%
With supplemental firing	96%

Annual operations

Electric output (MWh)	56,289
Thermal output (MMBtu)	
Power generation only	251,447
Supplemental firing	137,827
Total	389,274

Fuel consumption (MMBtu)		
Power generation only		638,112
Supplemental firing		140,640
Total		778,752
Total electricity consumed (MWh)		20,400
Electricity generated (MWh)		56,289
Electricity purchased (MWh)		-
% of electricity requirements generated		276%
Electricity sold (MWh)		35,889
% of electricity output sold		64%
Assumed value of electricity sold ($/MWh)	$	15.0
Total thermal energy consumed (MMBtu)		611,106
Steam thermal energy consumed (MMBtu)		397,219
Thermal energy generated with cogen (MMBtu)		389,274
% of steam thermal produced with cogen		98%
Steam energy generated with non-cogen plant		7,944

Appendix H-4: Chippewa Valley Ethanol
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **6.98 MW net power output**

Economic Analysis with Sensitivity to Gas Prices

Credit for boiler capacity?	**no**			
Investment tax credit?	**no**			
Net metering?	**no**			
Capital costs				
Capital cost ($/kW)	$ 890			
Gross capital cost ($)	$ 6,543,280			
Boiler capacity credited (MMBtu/hour)	-			
Boiler capacity type	gas/oil			
Boiler capacity credit ($ per MMBtu/hour)	$ 20,000			
Boiler capacity credit ($)	$ -			
Investment tax credit (%)	0%			
Investment tax credit ($)	$ -			
Net capital cost ($)	$ 6,543,280			
Operating costs				
Natural gas cost ($/MMBtu)	$5.00	$4.00	$3.00	$2.00
Labor cost per FTE	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Number of FTEs	1.0	1.0	1.0	1.0
Non-fuel, non-labor O&M costs ($/kWh)	$ 0.0058	$ 0.0058	$ 0.0058	$ 0.0058
Avoided electricity cost ($/kWh)	$ 0.036	$ 0.036	$ 0.036	$ 0.036
Estimated increase in $/kWh purchased	0%	0%	0%	0%
Annual operating costs				
Fuel	$ 3,893,761	$ 3,115,009	$ 2,336,257	$ 1,557,504
Labor	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Non-fuel, non-labor O&M costs ($/kWh)	$ 326,474	$ 326,474	$ 326,474	$ 326,474
Additional cost for power purchased	$ -	$ -	$ -	$ -
Total	$ 4,270,235	$ 3,491,483	$ 2,712,731	$ 1,933,979
Annual savings				
Avoided fuel for thermal generation	$ 2,330,984	$ 1,864,787	$ 1,398,590	$ 932,393
Avoided electricity costs	$ 737,760	$ 737,760	$ 737,760	$ 737,760
Revenue from electricity sales	$ 538,330	$ 538,330	$ 538,330	$ 538,330
Total annual savings	$ 3,607,074	$ 3,140,877	$ 2,674,680	$ 2,208,484
Net operating savings	$ (663,162)	$ (350,606)	$ (38,051)	$ 274,505
Simple payback (years)	(9.9)	(18.7)	(172.0)	23.8

Appendix H-4: Chippewa Valley Ethanol
Option 2, Combustion Turbine CHP

Combustion Turbine CHP **6.98 MW net power output**
Economic Analysis with Sensitivity to Avoided Power Costs

Assumes Natural Gas Cost of $ 5.00 per MMBtu

Cost factors								
Avoided electricity cost ($/kWh)	$	0.035	$	0.045	$	0.055	$	0.065
Revenue for electricity sold ($/kWh)	$	0.015	$	0.015	$	0.015	$	0.015
Estimated increase in $/kWh purchased	0%		0%		0%		0%	
Annual operating costs								
Fuel	$	3,893,761	$	3,893,761	$	3,893,761	$	3,893,761
Labor	$	50,000	$	50,000	$	50,000	$	50,000
Non-fuel, non-labor O&M costs ($/kWh)	$	326,474	$	326,474	$	326,474	$	326,474
Additional cost for power purchased	$	-	$	-	$	-	$	-
Total	$	4,270,235	$	4,270,235	$	4,270,235	$	4,270,235
Annual savings								
Avoided fuel for thermal generation	$	2,330,984	$	2,330,984	$	2,330,984	$	2,330,984
Avoided electricity costs	$	1,970,104	$	2,532,990	$	3,095,877	$	3,658,764
Revenue from electricity sales	$	538,330	$	538,330	$	538,330	$	538,330
Total annual savings	$	4,839,417	$	5,402,304	$	5,965,191	$	6,528,078
Net operating savings	$	569,182	$	1,132,069	$	1,694,956	$	2,257,842
Simple payback (years)		11.5		5.8		3.9		2.9

Appendix I – Emissions Comparison

Cogeneration

Cogeneration system	
Power generated (MWH)	56,289
Thermal energy produced (MMBtu)	389,274
Fuel consumed (MMBtu)	778,752

Emissions (lbs/MMBtu fuel)	
Nitrogen oxides	0.1000
Sulfur dioxide	0.0007
Particulates	0.0047
Carbon dioxide	115

NO x emission control technology: Low NOx burner with water injection

Emissions	
Nitrogen oxides (lbs)	77,875
Sulfur dioxide (lbs)	543
Particulates (lbs)	3,622
Carbon dioxide (tons)	44,778

Conventional Approach

Major Xcel Intermediate load plants

Emissions (lbs/MWH)	
Nitrogen oxides	16.920
Sulfur dioxide	12.667
Particulates	0.109
Carbon dioxide	1.272

Emissions	
Nitrogen oxides (lbs)	952,418
Sulfur dioxide (lbs)	712,993
Particulates (lbs)	6,160
Carbon dioxide (tons)	71,623

Gas-fired boilers

Thermal energy produced (MMBtu)	389,274
Boiler efficiency (HHV)	82%
Fuel consumption (MMBtu)	474,725

Unit emissions	(lbs/MWh)	(lbs.)
Nitrogen oxides (lbs/MWH)	0.1000	47,472

Sulfur dioxide (lbs/MWH)	0.0007	331
Particulates (lbs/MWH)	0.0047	2,208
Carbon dioxide (tons/MWH)	115	27,297

Total emissions for conventional approach

Nitrogen oxides (lbs)	999,891
Sulfur dioxide (lbs)	713,324
Particulates (lbs)	8,368
Carbon dioxide (tons)	98,920

Comparison of emissions

	Cogeneration	Conventional
Nitrogen oxides (10,000 lbs)	8	100
Sulfur dioxide (10,000 lbs)	0	71
Carbon dioxide (1,000 lbs)	45	99

Appendix J: New Condensing Power Plant

NEW CONDENSING POWER PLANT

Technology type	Large gas turbine combined cycle
Number of units	1
Capacity per unit (Mwe)	259.3
Fuel mix	All natural gas

Power plant capacity and efficiency

		MW	MMBtu/hr	Efficiency
Fuel input				
Heat rate (Btu/KWHe)	6,315			
Fuel input (LHV) per hour			1637.48	
Energy outputs				
Electric output		259.3	884.99	54.0%
Thermal output		-	0.00	0.0%
Total efficiency				54.0%

Transmission losses (% of input fuel) 7.4%

Fuel consumption

	% of total	MMBtu/hr
Natural gas	100%	1,637.48
Fuel oil (# 2)		
Coal		
Biomass		
Total		1,637.48

Million Btu of fuel per MWH of delivered electricity 6.82

Capital cost

Cost per KWHe	$	600
Cost	$	155,580,000

Operation and maintenance costs

Fixed cost		0.0%	of capital cost
Variable cost	$	5.00	per MWHe

Manufacturer and model assumed for technical performance

General Electric S-109EC, with 3 pressure levels, reheat, heat recovery feedwater heating.

ANNUAL COST FACTORS

Financing cost factors

Costs for financing, capitalized interest, reserves (% of construction cost)	***15%***
Interest rate	***7%***
Term (years)	***20***
Capital recovery factor	0.09439

Operating cost factors

Natural gas cost ($ per MMBtu)	***$***	***3.00***
Coal cost ($ per MMBtu)		
Oil cost ($ per MMBtu)		
Biomass cost ($ per MMBtu)		
Operating staff (Full-Time-Equivalents)		***16***
Average $ per FTE	***$***	***50,000***
Administrative staff (Full-Time-Equivalents)		***20***
Average $ per FTE	***$***	***50,000***
Non-personnel general/administrative cost (% of admininistrative staff cost)		***15%***
Capacity factor		***80%***

Annual electricity generated (MWH)	1,817,174
Annual electricity delivered after transmission losses (MWH)	1,682,703

ANNUAL COSTS (million $)

Debt service			$	14.69
Fuel			$	34.43
Labor			$	0.80
General and administrative				
Personnel	$	1.00		
Other G&A	$	0.15		
Subtotal			$	1.15
Maintenance			$	9.09
Total			$	60.15

Summary of annual and unit costs

	Million $		cents per kWh generated	cents per kWh delivered
Fuel	$	34.43	1.89	2.05
Maintenance and supplies	$	9.09	0.50	0.54
Labor	$	0.80	0.04	0.05
G&A	$	1.15	0.06	0.07
Subtotal operating costs	$	45.46	2.50	2.70

Debt service	$	14.69	0.81	0.87
Total costs	$	60.15	3.31	3.57